BART DETERMINATION STUDY

for

Milton R. Young Station Unit 1 and 2
Minnkota Power Cooperative, Inc.

October 2006
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INDEX AND CERTIFICATION

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Certification

I hereby certify, as a Professional Engineer in the state of North Dakota, that the information in this document was assembled under my direct personal charge. This report is not intended or represented to be suitable for reuse by the Minnkota Power Cooperative, Inc. or others without specific verification or adaptation by the Engineer. This certification is made in accordance with the provisions of the laws and rules of the North Dakota State Board of Registration under Title 28 Administrative Code.

Minnkota Power Cooperative, Inc.
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Best Available Retrofit Technology Determination Study

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EXECUTIVE SUMMARY

This document presents the Best Available Retrofit Technology (BART) analysis for each of three major pollutants: nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM) for Minnkota Power Cooperative, Inc.'s (Minnkota's) Unit 1 and Square Butte Electric Cooperative's (Square Butte's) Unit 2 at the Milton R. Young Station (MRYS) located near Center, North Dakota. On July 6, 2005, the United States Environmental Protection Agency (U.S. EPA or EPA) finalized the Regional Haze Regulations (RHR) and Guidelines for BART Determinations. The final regulations require eligible sources to be analyzed to determine a BART emission limit for nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). The North Dakota Department of Health (NDDH) reviewed the operational history of North Dakota sources and determined which sources were BART-eligible and provided a state-specific modeling protocol for use in the analysis. Milton R. Young Station Unit 1 and Unit 2 were determined to be BART-eligible by the NDDH. As discussed in the introduction to the BART analysis, small emission units at MRYS produce emissions in levels anticipated to be too low to affect visibility in Class 1 areas and were excluded from further consideration in the study. This BART determination was conducted in accordance with the eligibility conclusion made by NDDH and follows the NDDH protocol.

Once a source is determined to be eligible, there are five predefined steps for conducting a BART analysis for each pollutant. Steps 1 through 3 include identifying control technologies, evaluating feasibility, and ranking feasible options by control effectiveness. Step 4 involves a technical evaluation of various impacts related to each feasible control technology. The evaluation reviews include economics, energy, and non-air environmental impacts. Visibility impairment impacts in the nearest Class 1 areas for the dominant controls are evaluated in Step 5. A summary ranking of control technologies for regulated pollutants that provide a cost effective system of emission reduction and visibility impact reduction is developed. The results of conducting this five step analysis is a recommendation for selection of BART, which is then translated into an emission rate constituting BART that must be achieved by the eligible source for each major regulated pollutant. Although the impacts requiring analysis are explicitly stated within the RHR and Guidelines, no methodology is provided for using the impacts to select a control technology. Thus, each State has discretion in weighing the various impacts identified in the BART analysis for emission sources within their jurisdiction based upon source characteristics, reviewed technologies, and background information used to perform the evaluation.

This analysis used several reference works, including the RACT/BACT/LAER Clearinghouse (RBLC), to identify which control technologies to evaluate. The technologies were then reviewed for feasibility and those deemed to be infeasible were eliminated from further study. The feasible control technologies were ranked by control efficiency and estimates of costs to implement, operate, and maintain such technologies were developed. Comparing average and incremental control costs allowed inferior controls to be removed from the list. Remaining technologies were evaluated based upon other impacts and predicted reductions in visibility impairment. The final BART recommendations were then made for each pollutant and are summarized in the tables below.

Prior to the completion of this analysis, Minnkota entered into a Consent Decree (CD) with the EPA and the NDDH. This CD requires Minnkota and Square Butte to perform a Best Available Control Technology (BACT) analysis for NO_X emissions controls, and establishes minimum removal rates for SO_2 and maximum PM emission rates for Unit 1 and Unit 2 at MRYS. For NO_X emissions control, certain control technologies were evaluated as required by the CD. The BART evaluation process for NO_X control technologies was modified to use the BACT analysis study. Submittal of the BACT analysis and additional support documents to the NDDH occurred on October 6, 2006, March 19, and April 23, 2007 respectively. For sulfur dioxide and particulate matter emissions, a BART analysis for each Unit at MRYS was performed.

Based upon an evaluation of the 90th percentile visibility impairment modeling results, the control technologies recommended as BACT for NO_X emissions and those recommended as BART for SO_2 and PM emissions had an acceptable impact reduction. Because there was an acceptable impact reduction in all cases, the BART recommendation consists of the control technologies at the modeled emission rates. The BART recommendations for each pollutant and each unit are summarized in the tables below. The recommended BART emission rates are presented as a 30-day rolling average to account for variations in boiler operation, fuel sulfur content and fly ash properties.

MRYS Unit 1 Recommended BART 30-Day Rolling Average

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Advanced Separated Over Fire Air (ASOFA) and Selective Non-Catalytic Reduction (SNCR)	0.36*
SO_2	Wet Flue Gas Desulfurization (FGD) Process	0.15
PM	Maintain Existing Electrostatic Precipitator (ESP)	0.030

* Excludes startups. See referenced BACT analysis for a detailed discussion.

MRYS Unit 2 Recommended BART 30-Day Rolling Average

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Advanced Separated Over Fire Air (ASOFA) and Selective Non-Catalytic Reduction (SNCR)	0.35*
SO_2	Upgrade of Existing Wet Flue Gas Desulfurization (FGD) Process	0.30
PM	Maintain Existing Electrostatic Precipitator (ESP)	0.030

* Excludes startups. See referenced BACT analysis for a detailed discussion.

1.0 INTRODUCTION

The United States Environmental Protection Agency (U.S. EPA or EPA) finalized the Regional Haze Regulations (RHR) and Guidelines for Best Available Retrofit Technology (BART) Determinations[1] in the Federal Register on July 6, 2005 (70 FR 39104). BART is defined as “an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by a BART-eligible source. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology” (70 FR 39163). This document presents the BART analysis for each of three major pollutants: nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM) for Minnkota Power Cooperative, Inc.’s (Minnkota’s) Unit 1 and Square Butte Electric Cooperative’s (Square Butte’s) Unit 2 at the Milton R. Young Station (MRYS) located near Center, North Dakota.

1.1 BART ELIGIBILITY

A BART eligible source is one that meets three criteria identified by EPA in the RHR and Guidelines for the determination of BART. A source is BART eligible if operations fall within one of 26 specifically listed source categories (70 FR 39158), the source entered into service between August 7, 1962 and August 7, 1977, and the source has the potential to emit 250 tons per year or more of a visibility-impairing air pollutant (SO_2, NO_X or PM). The North Dakota Department of Health (NDDH) reviewed the operational history of sources within North Dakota and independently determined which of those sources are BART-eligible. The NDDH classified the electric generating units (EGUs) at Milton R. Young Station as BART-eligible. For the purposes of this report, the NDDH’s determination will be used and Units 1 and 2 at MRYS are assumed to be subject to a BART analysis.

[1] “Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations”; Environmental Protection Agency; Federal Register, Volume 70, No. 128; July 6, 2005.

1.2 BART ANALYSIS PROCESS

Where a particular source is determined to be eligible, the general steps for determining BART for each pollutant are as follows (70 FR 39164):

STEP 1 - Identify all available retrofit control technologies (within the BART Guidelines).
STEP 2 - Eliminate technically infeasible options.
STEP 3 - Evaluate control effectiveness of remaining control technologies.
STEP 4 - Evaluate the following impacts for each feasible control technology and document results:

(70 FR 39166).

- The cost of compliance.
- The energy impacts.
- The non-air quality environmental impacts.
- The remaining useful life of the source.

STEP 5 – Evaluate the visibility impacts.

Minnkota Power Cooperative, Inc. retained Burns & McDonnell to assist in the completion of the Best Available Retrofit Technology analysis for Milton R. Young Station. Burns & McDonnell is a full service engineering, architectural, construction and environmental firm. The company plans, designs and constructs electric generating facilities and has been providing environmental services to the power industry since the 1970s. As a result of their long history providing these services, Burns & McDonnell has extensive experience in permitting, Best Available Control Technology (BACT) studies and control technology analysis similar to a BART analysis.

1.2.1 IDENTIFICATION OF RETROFIT CONTROL TECHNOLOGIES

The initial step in the BART determination is the identification of retrofit control technologies. In order to identify the applicable control technologies, several reference works are consulted. A preliminary list of control technologies and their estimated capabilities is developed.

1.2.2 FEASIBILITY ANALYSIS

The second step of the BART process is to evaluate the control processes that have been identified and determine if any of the processes are technically infeasible. The BART guidelines discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the "availability" and "applicability" of each control technology.

A control technology is considered available, "if the source owner may obtain it through commercial channels, or it is otherwise available in the common sense meaning of the term" or "if it has reached the stage of licensing and commercial availability." On the contrary, a control technology is not considered available, "in the pilot scale testing stages of development." (70 FR 39165) When considering a source's applicability, technical judgment must be exercised to determine "if it can reasonably be installed and operated on the source type." The EPA also does not "expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type." (70 FR 39165) "A technology that is available and applicable is technically feasible." (70 FR 39165)

1.2.3 EVALUATE TECHNICALLY FEASIBLE CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to evaluate the control effectiveness of the technically feasible alternatives. During the feasibility determination in step 2 of the BART analysis, the control efficiency is reviewed and presented with the description of each technology. The evaluation of the technically feasible BART alternatives concludes with the alternatives ranked in descending order of control effectiveness.

1.2.4 IMPACT ANALYSIS

Step four in the BART analysis procedure is the impact analysis. The BART Determination Guidelines (70 FR 39166) lists four factors to be considered in the impact analysis. The BART Determination will consider the following four factors in the impact analysis:

- The costs of compliance;
- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

The first three of the four factors considered in the impact analysis are discussed in the associated pollutant section. The remaining useful life of the source is included as part of the cost of compliance.

1.2.5 METHODOLOGY FOR ESTIMATED COSTS

The cost summary of each alternative is presented in the section for each pollutant. Installed capital and annual O&M cost estimates for each alternative are presented individually. The Levelized Total Annual Cost (LTAC) represents the levelized annual cost of procurement, construction and operation over a 20 year design life, in current (2006) dollars. The LTAC represents an annual payment in current day dollars sufficient to finance the project over its entire life.

In determining the LTAC, a Capital Recovery Factor and an O&M Levelization Factor were calculated from the project economic conditions and then applied separately to the estimated capital and O&M costs. The equation used is shown below.

$$LACC / NPV = \left(\frac{i_d (1 + i_d)^n}{(1 + i_d)^n - 1} \right) = CRF$$

Where,
LACC = Levelized Annual Capital Cost
NPV = Net Present Value of the capital investments required.
i_d = discount rate
n = design life in years
CRF = Capital Recovery Factor

Therefore:

LACC = CRF x NPV

For the economic conditions described in Table 1.2-1, the Capital Recovery Factor was calculated to be 0.08718.

In determining the levelized annual O&M cost the estimated annual O&M cost, the escalation rate, the discount rate, and the equipment life are taken into account. The O&M Levelization Factor (OMLF) was calculated as follows.

$$LAOMC / A_1 = \frac{\left(\frac{(1 + i)^n - 1}{i} \right)}{(1 + i)^n} \left(\frac{i_d (1 + i_d)^n}{(1 + i_d)^n - 1} \right) = OMLF$$

The inflation rate (i) used in the above calculation is determined as follows.

$$i = \left(\frac{1 + i_d}{1 + i_i} - 1 \right)$$

Where,
LAOMC = Levelized Annual O&M Cost
A_1 = Estimated annual O&M cost in current dollars
i_d = discount rate
i_i = escalation rate
i = inflation rate
n = design life in years
OMLF = O&M Levelization Factor

Therefore:

$$\text{LAOMC} = \text{OMLF} \times A_1$$

For the economic conditions described in Table 1.2-1, the Operating and Maintenance Levelization Factor was calculated to be 1.24873.

The Levelized Total Annual Cost, or LTAC is the sum of the levelized capital cost and the levelized O&M cost. Therefore:

$$\text{LTAC} = \text{LACC} + \text{LAOMC} = (\text{CRF} \times \text{NPV}) + (\text{OMLF} \times A_1) = 0.08718 \times \text{NPV} + 1.24873 \times A_1$$

The economic analyses presented in this report not only include the estimated capital and annual O&M costs for each alternative, but also the LTAC for economic comparison of the various alternatives.

Table 1.2-1 – Economic Factors[1]

Total Possible Operating Hours per Year	8,760
Plant Capacity Factor	85%
Amortization Life, Years	20
Cost of Money	6%
Property Taxes, Insurance, %	NA
Amortization Rate for APC Capital Costs	6%
Interest During Construction (IDC)	6%
Discount Rate	6%
Construction Cost Escalation	3%
Non-Fuel O&M Escalation	2.5%
Fuel (coal and natural gas) Escalation	2.5%
Operating Labor Rate, $/hr	$40.00
Auxiliary Electric Power Cost, $/MW-hr	$35.00

1. All costs are in 2006 dollars unless noted otherwise.

1.3 BART ANALYSIS APPROACH

The purpose of the Regional Haze Rule (RHR) is to address visibility impairment in mandatory Class 1 areas that results from the emission of SO_2, NO_X, PM, Volatile Organic Compounds (VOCs) and ammonia from certain major sources. The only control method for VOCs identified in the RACT/BACT/LAER Clearinghouse (RBLC) database is good combustion practices. This control technique is already in place at MRYS. If an analysis were performed for VOCs, good combustion practices would be the most probable method chosen for BART. The visibility impact of VOCs and ammonia are considered negligible for a BART analysis, according to the NDDH's November 2005 modeling protocol[2], and are not addressed further in this report. Before the actual BART analysis can begin for SO_2, NO_X, and PM, the approach used to conduct the analysis should be addressed. The following sections present specific subjects related to MRYS's background, which warrant mention due to their effects on the contents of the report.

1.3.1 BACKGROUND

Minnkota Power Cooperative, Inc. operates the Milton R. Young Station near Center, North Dakota. MRYS is a steam electric generating plant with two units. Unit No. 1 is a Babcock & Wilcox (B&W) cyclone-type coal-fired boiler burning lignite coal, serving a turbine generator with a nameplate rating of 257 MW.[3] Particulate control is provided by a Research-Cottrell Electrostatic Precipitator rated at approximately 99% control. Unit 1 has no sulfur dioxide (SO_2) control system and exhausts to a 300 foot tall stack. Unit No. 2 is a B&W cyclone-fired unit burning lignite coal, with a turbine-generator name plate rating of 477 MW.[4] Particulate control for Unit 2 is provided by a Wheelabrator-Lurgi precipitator rated at approximately 99% control. Unit 2 has a Combustion Equipment Associates wet flue gas desulfurization (FGD) system (modified by Combustion Engineering) that treats approximately 78 percent of the flue gas with the remaining flue gas by-passed for stack gas reheat. The FGD system achieves approximately 75 percent SO_2 removal and exhausts to a 550 foot tall stack. Unit 1 began commercial operation on November 20, 1970 and Unit 2 on May 11, 1977.

[2] "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota"; North Dakota Department of Health, Division of Air Quality; November, 2005.
[3] "Generator Nameplate Data"; Emissions & Generation Resource Integrated Database (eGRID); U.S. Environmental Protection Agency; April, 2003.
[4] Ibid footnote 3 reference.

On June 17, 2002, Minnkota Power Cooperative, Inc. received a Notice of Violation (NOV) from the EPA. The NOV states that Minnkota allegedly violated the Prevention of Significant Deterioration (PSD) regulations. The NOV was issued pursuant to Section 113 of the Clean Air Act. The alleged violation was caused by modifications to both Unit 1 and 2 at MRYS which allegedly resulted in a potential increase of SO_2, NO_X and PM. Without an admission of liability, Minnkota entered into a settlement in the form of a Consent Decree (CD) with the EPA and NDDH to resolve the issues. The CD requires that Minnkota perform a BACT analysis for NO_X emissions and to install controls in a two-part, phased approach. SO_2 and PM emissions for Unit 1 and Unit 2 at MRYS are required to achieve at or below the specified levels of unit emission rates (lb per million Btu), and also minimum levels of removal for sulfur dioxide emissions. The effect of the CD on the BART analysis and the requirements to install emission controls NO_X, SO_2, and PM are discussed later in the report.

1.3.2 CONTROL TECHNOLOGY EVALUATION AND BACT VS. BART

As stated above, once a source is determined to be eligible, there are general steps for conducting a BART analysis for each pollutant. All retrofit control technologies are first identified. A brief review of the processes and their capabilities is then performed to determine availability and feasibility. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to control capability and an analysis then reviews the probable impacts of each technology. The visibility impact is included in the impact analysis. Finally, the results of the analyses are tabulated and possible BART control options are listed.

As stated in the proposed BART guidelines dated 5 May 2004 (69 FR 25218), a BART analysis is similar to a Best Available Control Technology (BACT) analysis.

> “The process for a BART analysis is very similar to the BACT review as described in the New Source Review Workshop Manual (Draft, October 1990). Consistent with the Workshop Manual, the BART engineering analysis requires that all available control technologies be ranked in descending order of control effectiveness (i.e. percent control). You [meaning States] must examine the most stringent alternative first. That alternative is selected as the ‘‘best’’ unless you demonstrate and document that the alternative cannot be justified based upon the consideration of the five statutory factors discussed below. If you eliminate the most stringent technology in this fashion, you then consider the next most stringent alternative, and so on.

> Although very similar in process, BART reviews differ in several respects from the BACT review described in the NSR Draft Manual."

The proposed guidelines stated that a BART analysis is similar to a BACT review and provided a few examples of similarities and differences, but it did not explicitly state how the two analyses could be used in conjunction to obtain a determination. Because BACT and BART are similar, there are many aspects that can be combined to reduce the steps of an analysis. However, because there are some differences, a BART analysis must address some additional aspects that a BACT review does not.

A BART analysis is always conducted for existing sources and a BACT review is usually conducted for a new source. Because BACT is usually performed for a source that is a new design or reconstruction, the review must take into account all available technologies and must include the most effective controls that have been demonstrated on similar units. BACT is considered to be more stringent than BART because it usually is not limited by the design of existing equipment or current operating conditions as is required for a retrofit application. Although MRYS is eligible to perform an analysis to determine BART, the Consent Decree (CD) also requires that MRYS install levels of control equivalent to BACT. Thus, the BART analysis can be shortened to only include the BACT-level control technologies specified in the CD or technologies that are more stringent.

Although Unit 1 and Unit 2 at MRYS are BART-eligible, the Consent Decree (CD) also requires that the NDDH establish BACT for NO_X control. With the specification to establish BACT for NO_X, the BART analysis was modified to replace the first four BART evaluation steps with the NO_X BACT analysis. The first four steps of BART are usually used to identify technologies, determine feasibility and evaluate cost, energy, non-air quality and useful life impacts. Because a BACT analysis results in the selection of the best available control technology, the visibility impacts evaluation is the only remaining step in the determination that must be performed to satisfy BART for NO_X. The MRYS NO_X BACT analysis study reports and additional support documents were submitted to the NDDH on October 6, 2006, March 19, and April 23, 2007 respectively. In addition, because the CD also requires a minimum level of control for both SO_2 and PM, this analysis evaluates the visibility impairment impacts of the BACT-level control technologies specified for SO_2 and PM. The BART analysis does not review technologies that do not achieve the minimum level of control specified in the CD. The final BART recommendation is based upon an acceptable degree of visibility improvement in Class 1 areas.

1.3.3 EMISSION SOURCE APPLICABILITY

There are two subjects within the Guidelines related to the applicability of BART to emission sources. The first subject deals with the presumptive BART emission limits and their application to power plants smaller than 750 MW in size. The Guidelines for BART Determination include the following statement with regard to presumptive BART for SO_2 (70 FR 39171):

> "You [meaning States] must require 750 MW power plants to meet specific control levels for SO_2 of either 95 percent control or 0.15 lbs/mmBtu, for each EGU greater than 200 MW that is currently uncontrolled unless you determine that an alternative control level is justified based on a careful consideration of the statutory factors. For a currently uncontrolled EGU greater than 200 MW in size, but located at a power plant smaller than 750 MW in size, such controls are generally cost effective and could be used in your BART determination….."

Similarly for NO_X, the EPA states (70 FR 39171):

> "For coal-fired EGUs greater than 200 MW located at greater than 750 MW power plants and operating without post-combustion controls, we have provided presumptive NO_X limits differentiated by boiler design and type of coal burned. You may determine that an alternative control level is appropriate based on a careful consideration of the statutory factors. For coal-fired EGUs greater than 200 MW located at power plants 750 MW or less in size and operating without post-combustion controls, you should likewise presume that these same levels are cost-effective."

For power plants greater than 750 MW in size, the EPA requires state agencies to apply the presumptive limits for BART as a floor for NO_X control. However, for power plants smaller than 750 MW in size, the presumptive BART limits are described as being "cost-effective" but not set as a minimum performance requirement. Thus, BART for EGUs at power plants smaller than 750 MW in size, like MRYS, is not required to meet the presumptive limits. This BART analysis for MRYS will evaluate potential control options that achieve the control levels and are below the emission limits set forth in the Consent Decree. Because the States have final discretion in how they choose to weigh the various impacts as part of their BART determinations for each EGU emission source, the recommended BART control options may not achieve the EPA's presumptive BART limits based upon the visibility analysis.

The second part of the Guidelines that should be addressed relates to which emission units are subject to BART for a particular pollutant. The Guidelines state that:

> "Once you determine that a source is subject to BART for a particular pollutant, you must establish BART for that pollutant. The BART determination must address air pollution control measures for each emissions unit or pollutant emitting activity subject to review." (70 FR 39163)

According to this statement, the BART determination must consider any emission unit that emits the pollutant of concern (i.e., NO_x, SO_2 and PM) regardless of size. The BART analysis for MRYS will review control options for the main boilers for Unit 1 and Unit 2. Smaller emissions sources at the facility are anticipated to provide negligible contribution to visibility impacts from MRYS in Class 1 areas. Smaller sources at MRYS are discussed in Section 1.3.4 and 1.3.5.

1.3.4 SMALL SOURCE EMISSION UNITS

The BART determination must consider any emission unit that emits the pollutant of concern (i.e., NO_x, SO_2 and PM) regardless of size. However, smaller emissions sources (e.g., auxiliary boilers and emergency generators) at the facility are anticipated to provide negligible contributions to visibility impairment in Class 1 areas. The nearest Class 1 area is Theodore Roosevelt National Park (TRNP) located approximately 160 km to the west. Although technically eligible, smaller source emissions units were not reviewed because they have limited hours of operation or they are material handling sources with a level of emissions anticipated to be too low to affect visibility impact on TRNP. Consequently, small emission sources are excluded from further consideration in the study.

1.3.5 FUGITIVE DUST

The primary source of fugitive dust is from the outside coal storage area and other plant activities normally found at a coal-fired electrical generating facility. The coal stockpile, access roads and plant activities are performed and maintained with good operating practices. On the coal stockpile and on other applicable fugitive sources, dust suppression is achieved through the use of water sprays or surfactants. The level of fugitive PM emissions is not expected to affect the visibility in Class 1 areas based upon the approximate 160 km distance to the nearest Class 1 area, the large particle size and relatively small emission rates. As such, fugitive sources were not evaluated in this BART analysis for MRYS.

1.3.6 CONDENSABLE PARTICULATE

Particulate matter emissions are composed of filterable and condensable particles. Condensable particulate matter (condensable PM) may react with atmospheric or flue gas constituents as flue gas moves through the different processes and then either condenses into a droplet, coalesces into a solid particle, or forms a solid particle as more volatile components evaporate. Condensable PM may include both organic and inorganic constituents. Organic constituents in the flue gas can exist as a vapor at stack temperatures and a liquid or solid at ambient temperatures. Control technologies designed to minimize the formation of condensable organic emissions are the same technologies that are used to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions. A review of the RBLC database shows that good combustion practices are universally used to control CO/VOC emissions for similar units. Both MRYS units already practice good combustion practices while maintaining combustion efficiency in the boiler and controlling NO_X emissions. Because good combustion practices would likely be considered BART and are already in use at both units, the organic portion of condensable PM is not addressed further in this report.

Sulfuric acid (H_2SO_4) mist is the most widely recognized form of inorganic condensable PM emitted by combustion sources. Other inorganic condensable PM constituents may include to a lesser extent other acid gases, ammonium sulfate ($(NH_4)_2SO_4$), and unidentified inorganic species. Control technologies designed to reduce sulfuric acid mist will also reduce the other inorganic constituents. H_2SO_4 is typically generated in the flue gas when sulfur trioxide (SO_3) reacts with water. SO_3 is a by-product created during the combustion of fuels containing sulfur and is formed when sulfur dioxide (SO_2) in the flue gas is oxidized. Limited data is available on the quantity of SO_2 that will be converted to SO_3 in a lignite fired unit. Estimates of the conversion range from 0.2 to 1.0 percent.

Combustion controls commonly used to control NO_X (e.g., staged combustion and separated overfire air) provide a co-benefit of sulfuric acid mist control by limiting the oxygen available in the boiler and reducing formation of SO_3 in the boiler. The H_2SO_4 vapor will adsorb on the fly ash as the flue gas cools under appropriate temperature and moisture conditions. Consequently, when those conditions exist, H_2SO_4 is removed from the gas stream by particulate control equipment. Control technologies designed to remove SO_2 will also achieve SO_3 removal and reduce emissions of H_2SO_4. Typical SO_3 removal associated with a wet FGD process is 40 to 60 percent, and higher removal is typical for semi-dry FGD processes. The Southern Company estimates a minimum 50% reduction in H_2SO_4 emissions for use of a FGD process.[5] Thus, control technologies used to control NO_X, SO_2 and filterable PM are also able to provide H_2SO_4 control.

Recommended BART for condensable PM is the co-benefit of NO_X, SO_2 and filterable PM control devices to be analyzed in this report and is not addressed further. Therefore this BART analysis for particulate emissions investigates control methods to reduce filterable PM only.

1.4 METHODOLOGY FOR VISIBILITY IMPACTS DETERMINATION

In the BART Determination Guidelines, as discussed in Section 1.2 of this report, the EPA provides five basic steps for a case-by-case BART analysis. The fifth step involves evaluating visibility impacts utilizing dispersion modeling. Visibility impairment impacts for modeled pre-control and post-control emission levels and visibility improvements are to be assessed in deciViews (dV). The BART guidelines describe the thresholds for visibility impairment as:

> "A single source that is responsible for a 1.0 dV change or more should be considered to "cause" visibility impairment; a source that causes less than a 1.0 dV change may still contribute to visibility impairment..... any threshold that you (the States) use for determining whether a source "contributes" to visibility impairment should not be higher than 0.5 dV." (70 FR 39161)

The NDDH BART protocol does not distinguish between a source that "causes" or "contributes" to visibility impairment but follows the EPA's Regional Haze Rule threshold recommendations. Thus, 0.5 dV is the deminimis threshold level of visibility impairment impact for an otherwise BART-eligible source under the NDDH BART protocol. In other words, a BART-eligible source for which modeling predicts a visibility impairment impact of greater than 0.5 dV is deemed to have a visibility impairment impact and thus is subject to a BART analysis under the NDDH BART protocol. A BART-eligible source for which the modeling predicts less than a 0.5 dV impact would be deemed to not have a visibility impairment impact, and thus could be exempted from BART on that basis. Most

[5] "An Updated Method for Estimating Total Sulfuric Acid Emissions from Stationary Power Plants"; Monroe, Larry S. & Harrison, Keith E.; Southern Company Generation and Energy Marketing; Revised March, 2003.

noticeably, the EPA refrains from addressing the question of whether or not a difference in visibility impairment impact improvement of less than 0.5 dV between two BART alternatives would constitute equivalency under the visibility analysis, or if any difference in the model results, no matter how slight, should be interpreted as ranking one solution over the other. The approach taken in the BART analysis for MRYS incorporates the visibility impact analysis results as a verification of visibility improvement.

1.5 THE ROLE OF MODELING AND CALPUFF IN A BART ANALYSIS

The BART guidelines list visibility impact at a Class I area as one of the factors in a BART determination. The EPA interpreted the statutory provision of Section 169A of the Clean Air Act to require that a BART-eligible source is one that is “reasonably anticipated to cause or contribute” to regional haze if it can be shown that the source emits pollutants within a geographic area from which pollutants can be emitted and transported downwind to a Class I area (70 FR 39161). A Class I area, as listed by the EPA, is an area of the country with pristine air quality that is sensitive to changes in visibility. Two Class 1 areas have been identified for inclusion in the visibility analysis for MRYS. These are the Theodore Roosevelt National Park (TRNP), and the Lostwood National Wildlife Refuge (Lostwood NWR), which are approximately 160 and 180 km (100 and 112 miles), from Milton R. Young Station, respectively. For Class I areas more than 50 km from a source, the EPA has identified CALPUFF as a guideline model for long-range transport that is suitable for predicting potential changes in visibility. CALPUFF is a non-steady-state meteorological and air quality dispersion modeling system used to access long-range transport of pollutants.

The NDDH modeling protocol confirmed that the two Class I areas to be considered for visibility impairment analysis are the TRNP and Lostwood NWR. However, the three units or areas of the TRNP are to be treated as separate Class I areas for the analysis.

1.5.1 CALPUFF MODELING METHODOLOGY

Visibility impairment is caused by a combination of particles and gases in the atmosphere. Some particles and gases scatter light, others absorb light. The combined effect of scattering and absorption is called “light extinction” which is most commonly seen as haze. This haziness is measured in deciView (dV) units, and is related to light extinction coefficient by the following equation:

$$dV = 10 \ln(b_{ext}/10)$$

Where b_{ext} is light extinction coefficient in inverse megameters.

Visibility impairment is a function of light extinction. Light extinction occurs when light energy is either scattered or absorbed by particles in the air. The amount of moisture in the air also plays a role in light extinction. Certain gases combine with moisture in the air to form small light scattering particles. These gases, most notably SO_2 and NO_X, are significant components of coal-fired power plant emissions. Particulate Matter (PM) also contributes to light extinction. In the BART Determination Guidelines, the EPA states that "You [the State] may use PM_{10} as an indicator for particulate matter. We do not recommend the use of Total Suspended Particulates (TSP). As emissions of PM_{10} include the components of $PM_{2.5}$ as a subset, there is no need to have separate 250 ton thresholds for PM_{10} and $PM_{2.5}$; 250 tons of PM_{10} represents at most 250 tons of $PM_{2.5,}$ and at most 250 tons of any individual particulate species such as elemental carbon, crustal material, etc." (70 FR 39160). The NDDH modeling protocol states that particulate matter emissions should be specified as either coarse (PM_{10} minus $PM_{2.5}$) or fine ($PM_{2.5}$). The distinction between coarse and fine particulate occurs in the modeling.

The NDDH modeling protocol recommends a specific version of the CALPUFF modeling system as modified by the NDDH to specifically address terrain, climate, and emission characteristics of MRYS. (CALMET and CALPUFF were recompiled by the NDDH while the CALPOST executable used for this visibility analysis was the EPA guideline executable). Along with the CALPUFF modeling system, the NDDH also provided the RUC2-MM5 gridded wind field data (2000-2002), surface, upper air, and precipitation files, and CALMET and CALPUFF input files. The input files contained the specific coordinate grid points, wind field options, terrain, dispersion options, receptor coordinates and plume characteristics and other model parameters that the NDDH has determined best represents the region. The NDDH version of CALPUFF was used for modeling.

In order to predict the change in light extinction at TRNP and Lostwood NWR areas, SO_2, NO_X, and PM were modeled with CALPUFF using pre-control and post-control emission scenarios. A variety of post-control scenarios were used to determine the reduction in visibility impact for each control technology. The NDDH identified 104 receptors allocated over both TRNP and Lostwood NWR. These receptors are location points for which CALPUFF was used to perform a visibility calculation.

The BART guideline states that a visibility improvement is based upon the modeled change in visibility impacts, measured in deciViews, for the pre-control and post-control emission scenarios.

The comparison should be made for the 98th percent days (70 FR 39170). The NDDH modeling protocol provides additional clarification about BART applicability by stating, "…the context of the 98th percentile 24-hour delta-deciView prediction is with respect to days of the year, and is not receptor specific. A 24-hour prediction greater than 0.5 delta-deciView at any receptor in a Class I area would constitute a day of exceedance, and up to 7 days of exceedance would be allowed per year per Class I area (i.e., the 98th percentile is approximated by the eighth-highest daily prediction)." In other words, visibility impacts should be compared on an annual basis using the eighth highest day for comparison (365 * (1-.98) = 7 days of acceptable exceedance). However, NDDH subsequently advised that the delta-deciView comparison should be made at the 90th percentile to be consistent with the Western Regional Air Partnership (WRAP) protocol. Therefore, the analysis of visibility impairment impact reduction presented for each control scenario in this section is based on the 90th percentile value. The predictions of 24-hour 98th percentile deciView data are also provided in Appendix A.

1.5.2 MODELING SCENARIOS

Since a BART analysis is based on the degree of reduction achieved by the application of control technologies, the CALPUFF analysis examined multiple operating scenarios based upon the feasible control technologies identified for each pollutant. These scenarios represent the emissions of SO_2, NO_X, and PM under the following conditions:

- NDDH BART Modeling Protocol emission rates
- Post-Control NO_X emissions based upon recommended NO_X BACT-level emission rates from the Consent Decree
- Post-Control SO_2 and PM emissions based upon minimum emission rates as required by the Consent Decree and more stringent emission rates representative of potential BART alternatives

The emission rates modeled in each scenario are presented in Table 1.5-1.

Table 1.5-1 – Milton R. Young Station Modeling Scenarios

Scenario	Unit 1			Unit 2		
	NO_X (lb/hr)	SO_2 (lb/hr)	PM Coarse/Fine (lb/hr)	NO_X (lb/hr)	SO_2 (lb/hr)	PM Coarse/Fine (lb/hr)
Screening	Protocol	Protocol	Protocol	Protocol	Protocol	Protocol
1	1,070.7	Protocol	Protocol	2,011.6	Protocol	Protocol
2A	Protocol	723.1	Protocol	Protocol	1,574.4	Protocol
2B	Protocol	361.6	Protocol	Protocol	773.7	Protocol
3A	Protocol	Protocol	38.5 / 5.8	Protocol	Protocol	133.7 / 21.0
3B	Protocol	Protocol	77.1 / 11.6			
4	1,070.7	361.6	77.1 / 11.6	2,011.6	1,574.0	133.7 / 21.0
5	1,070.7	361.6	77.1 / 11.6	2,011.6	1,574.0	133.7 / 21.0

These scenarios represent the emission rates evaluated for consideration in making a BART recommendation. The emission rates presented in Table 1.5-1 correspond to control options and efficiencies considering the results of the NO_X BACT analyses and BART analyses for SO_2 and PM. The screening scenario from the NDDH BART modeling protocol is based on the historical maximum 24-hour emission rates for MRYS between 2000 and 2002. These rates were supplied to the NDDH by Minnkota, but were based upon operations that were not representative of stack conditions associated with new or modified retrofit control technologies.

Due to analyses performed on plant operations and historical emissions data, Minnkota has determined that unit operating conditions associated with these protocol rates are not representative of future maximum 24-hour emissions and has requested NDDH to allow the use of an alternative stack parameters and hourly baseline conditions for modeled post-control emission rates. NDDH agreed to the use of alternative post-control conditions. The alternative post-control scenarios are based upon various control technology emission reductions being applied to maximum 24-hour average heat input of 2,955 mmBtu/hr for Unit 1 and 5,158 mmBtu/hr for Unit 2. The emission rates associated with each scenario are discussed in the section related to the controlled pollutant.

As shown in Table 1.5-1, multiple modeling scenarios were conducted to determine the specific visibility impact reduction associated with the control of each pollutant. To determine a specific visibility impact for a particular pollutant, the emission rate for the pollutant of concern was changed from the protocol rate to the post-control rate. The other two major pollutants' emission rates were modeled at the protocol rates. Thus, any visibility impairment impact reduction for that modeling scenario was due solely to the application of the individual pollutant's control technology.

Additional modeling runs were conducted to determine the overall visibility impairment impact reduction caused by simultaneous application of all control technologies. In Table 1.5-1, modeling scenario 4 was run to determine the visibility impairment impact reduction resulting from simultaneous application of all control technologies for each unit individually. Modeling scenario 5 was run to determine the visibility impairment impact reduction resulting from simultaneous application of all control technologies for both units combined. The modeling results are summarized and discussed in the sections below.

2.0 NO_X BART EVALUATION

The BART analyses for NO_X emissions from MRYS Unit 1 and Unit 2 are described in this section. Technical descriptions of MRYS Unit 1 and Unit 2 boilers and existing air pollution control equipment are provided. As discussed in the introduction, Minnkota has entered into a Consent Decree (CD) that requires MRYS to install BACT-level NO_X control technologies on both units. For NO_X emissions control, the CD required that a complete BACT analysis be performed for MRYS to determine the applicable control technologies for each unit. The BACT analysis reports and additional support documents were submitted to the NDDH on October 6, 2006, March 19, and April 23, 2007 respectively.

It was assumed that a NO_X emissions control alternative considered as BACT would also satisfy similar ranking and non-visibility impacts of a BART determination process. Therefore, the alternative with the highest-performing, most cost-effective combination of control technologies identified by the NO_X BACT analysis for each Unit at MRYS that was not eliminated for technical infeasibility or adverse non-visibility impacts would be evaluated for impacts on the nearest Class 1 area in the subsequent BART visibility impairment analysis.

2.1 NO_X EVALUATION BASIS – UNIT 1

Milton R. Young Station Unit 1 includes a Babcock and Wilcox steam generator installed in 1970. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation. Original unit design steam generating capacity is 1.714 million lbs/hr at 1,920 psi with a fuel heat input of 2,510 mmBtu/hr. The boiler is fired by seven ten-foot diameter cyclone burners, arranged “three over four” across the front wall of the lower furnace. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the electrostatic precipitator (ESP). Unit 1’s boiler serves a turbine generator with a nameplate rating of 257 MW[6] and has a nominal 235 MW net design output capacity rating. Unit 1 is typically capable of sustained output of approximately 253 MW gross, and has an ultimate short-term maximum gross output (URGE) rating of 278 MW. The Unit 1 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from a

[6] Ibid EPA’s eGRID database; April, 2003.

mine located adjacent to the site. This method of firing solid fuel significantly influences the resulting nitrogen oxide concentration of the flue gases emitted from the boiler.

2.1.1 NO_X VISIBILITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 1

The remaining step for the BART NO_X analysis was to conduct a visibility improvement determination for Unit 1. Due to the association of the Consent Decree and requisite BACT analysis, the visibility analysis was the only subsequent impact evaluation necessary to establish BART. In addition, because the BACT analysis resulted in one control alternative for NO_X emissions control, only one related emission rate was modeled to determine the post-control visibility impairment impacts.

The modeling for Unit 1 uses two NO_X emission rates as a basis for the visibility impairment impacts. The NDDH BART protocol[7] NO_X emission rate of 2,855.2 lb /hr was modeled to determine a pre-control baseline visibility impact. This protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. This is equivalent to a unit NO_X emission rate of 0.898 lb/mmBtu at a boiler heat input rate of 3,180 mmBtu/hr. The baseline visibility impact was then compared with the results predicted from a modeled post-control NO_X emission rate based upon the control technology specified for Unit 1 in the BACT analysis.

According to the BACT analysis required by the Consent Decree, Selective Non-Catalytic Reduction (SNCR) post-combustion technology used in conjunction with an advanced combustion control application of Separated Overfire Air (ASOFA) was considered the best available technology and therefore was evaluated as BART for Unit 1. The second NO_X emission rate of 1,070.7 lb /hr was based upon application of SNCR with ASOFA control technologies for a reduction of approximately 62.5 percent from the protocol mass emission rate. This is equivalent to a unit NO_X emission rate of 0.362 lb/mmBtu at a more representative maximum 24-hour average boiler fuel heat input of 2,955 mmBtu/hr. The visibility modeling conditions are presented in Table 2.1-1.

[7] Ibid NDDH Final BART Protocol; November, 2005.

Table 2.1-1 – Milton R. Young Station Unit 1 Visibility Model Conditions

	NDDH Protocol	SNCR with ASOFA(1)
NO_X Emission Rate lb/hr	2,855.2	1,070.7
lb/mmBtu	0.898	0.362
Heat Input, mmBtu/hr	3,180.0	2954.5

(1) – Post-control NO_X emission rate reflects recommended BACT w/ adjusted reduction.

The results of the visibility modeling at the protocol baseline NO_X emission rate for MRYS Unit 1 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for the post-control NO_X emission rate showed a reduction in visibility impairment impact for all Class 1 areas. In addition, the modeled visibility impairment impact for all Class 1 areas at the post-control BACT-level NO_X emission rate was below the 0.50 dV threshold level. The modeling results are presented in Table 2.1-2.

Table 2.1-2 – NO_X Visibility Impairment Impacts and Reductions at NOx BACT Post-Control Emissions, MRYS Unit 1

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction (deciView)
	Protocol Emissions	Post-Control Emissions[2]	
TRNP-South Unit	0.549	0.377	0.172
TRNP-North Unit	0.628	0.413	0.215
TRNP-Elkhorn Ranch	0.374	0.266	0.108
Lostwood NWR	0.750	0.487	0.263

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.5-1 and the modeling results are presented in Appendix A.
2 - NO_X emissions reduction by 62.5% over NDDH protocol baseline case. This scenario assumes protocol emission rates for SO_2 and PM. Refer to Appendix A for complete protocol and revised post-control visibility model results.

The number of days predicted to have visibility impairment due to MRYS Unit 1 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol emission rates. The results are summarized and presented in Table 2.1-3. Similarly, the same information for the post-control NO_X emission rates is summarized and shown in Table 2.1-3. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control NO_X emission rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 areas, for Unit 1. The impact in terms of days exceeding 0.50 dV varies from an approximately 17% reduction for TRNP – Elkhorn in 2001 to an approximately 40% reduction for TRNP – South in 2000. The impact reduction in terms of days exceeding 1.00 dV varies from approximately 15% for TRNP – Elkhorn in 2002 to approximately 53% for TRNP – South in 2000.

A series of bar charts showing the difference in the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for the SNCR with ASOFA-controlled post-control emission rates with pre- and post-control SO_2 and PM alternatives is included in Figures 2.1-1 through 2.1-9.

Table 2.1-3 – Visibility Impairment Improvements for NOx BACT Post-Control Emissions – MRYS Unit 1 NO_X Scenarios

Class 1 Area	NO_X Control Technique	Days[1] Exceeding 0.5 dV in 2000	Days[1] Exceeding 0.5 dV in 2001	Days[1] Exceeding 0.5 dV in 2002	Days[1] Exceeding 1.0 dV in 2000	Days[1] Exceeding 1.0 dV in 2001	Days[1] Exceeding 1.0 dV in 2002	Consecutive Days[1] Exceeding 0.5 dV 2000	Consecutive Days[1] Exceeding 0.5 dV 2001	Consecutive Days[1] Exceeding 0.5 dV 2002
TRNP South	Protocol	38	30	48	19	15	26	3	3	4
	SNCR w/ ASOFA	23	20	35	9	10	19	2	3	3
TRNP North	Protocol	34	44	46	14	21	29	2	4	4
	SNCR w/ ASOFA	24	31	38	9	13	20	2	4	4
TRNP Elkhorn	Protocol	25	24	35	12	16	20	2	3	4
	SNCR w/ ASOFA	18	20	27	6	8	17	2	3	4
Lostwood NWR	Protocol	51	58	42	26	30	24	3	5	5
	SNCR w/ ASOFA	38	36	33	17	19	20	3	3	4

1 - Number of days for predicted visibility impairment impacts provided in Appendix A.

Figure 2.1-1 – Reduction in Days of Visibility Impairment > 0.5 dV
SNCR w/ ASOFA BART NO_X Control with Protocol Pre-Control SO_2 and PM Emissions
MRYS Unit 1

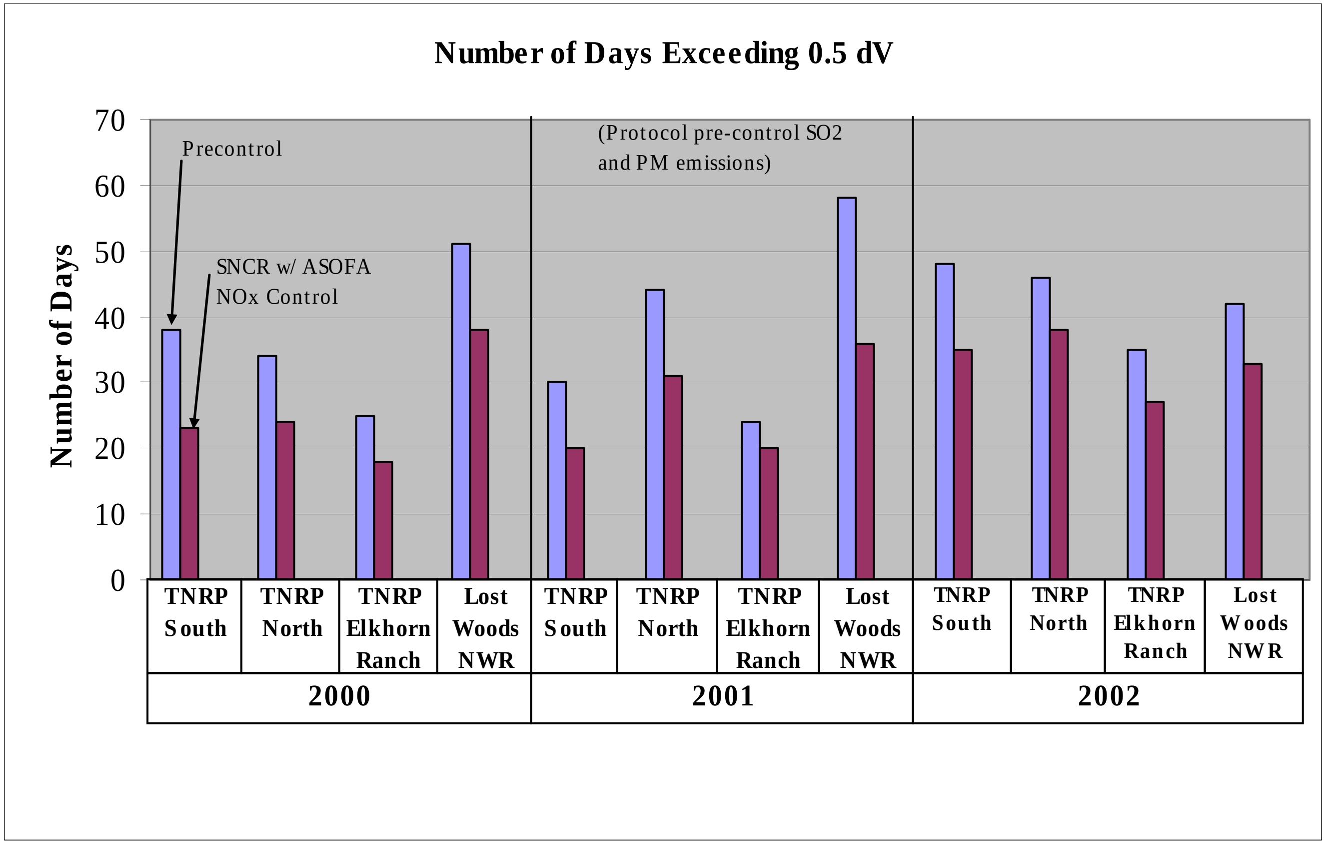


Figure 2.1-2 – Reduction in Days of Visibility Impairment > 1.0 dV
SNCR w/ ASOFA BART NO_X Control with Protocol Pre-Control SO_2 and PM Emissions
MRYS Unit 1

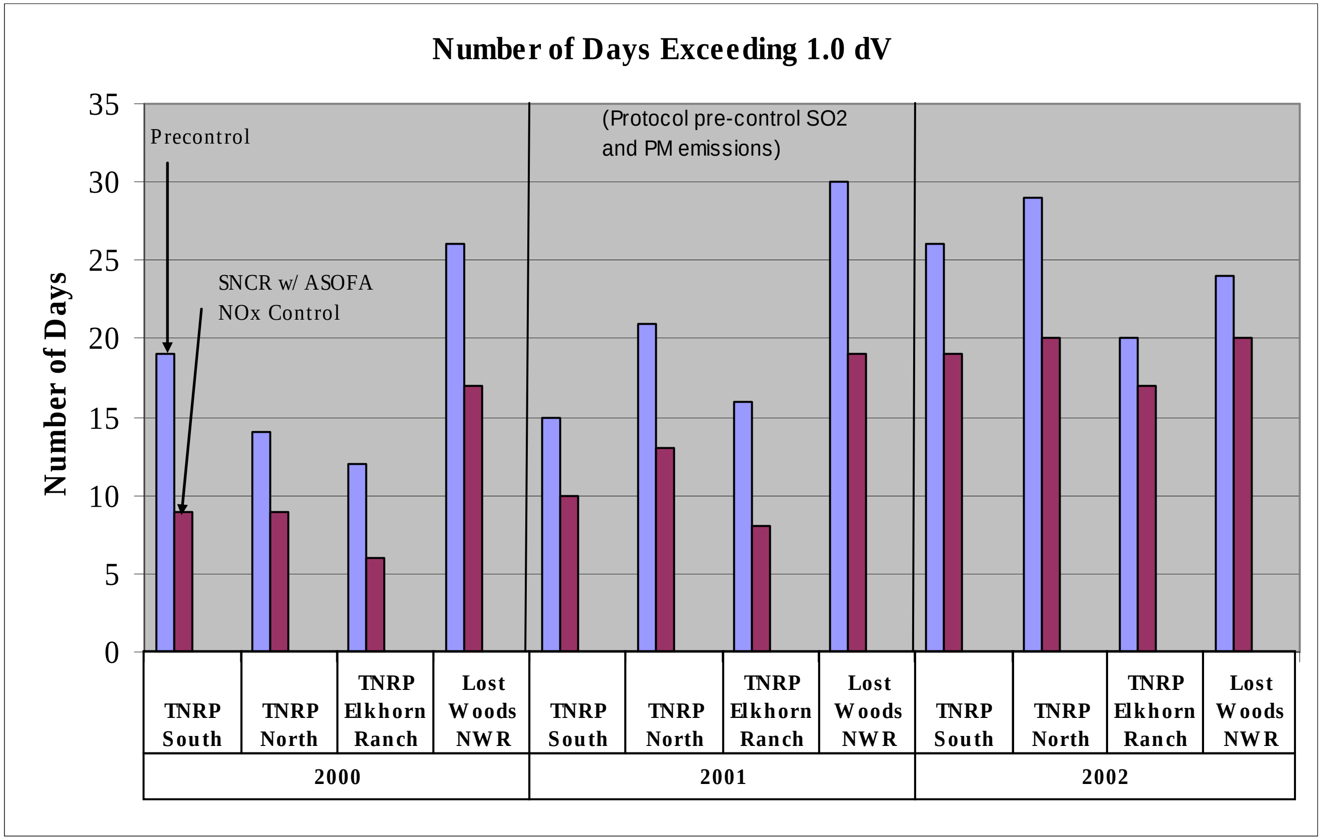


Figure 2.1-3 – Reduction in Maximum Consecutive Days Exceeding 0.5 dV
SNCR w/ ASOFA BART NO_X Control with Protocol Pre-Control SO_2 and PM Emissions
MRYS Unit 1

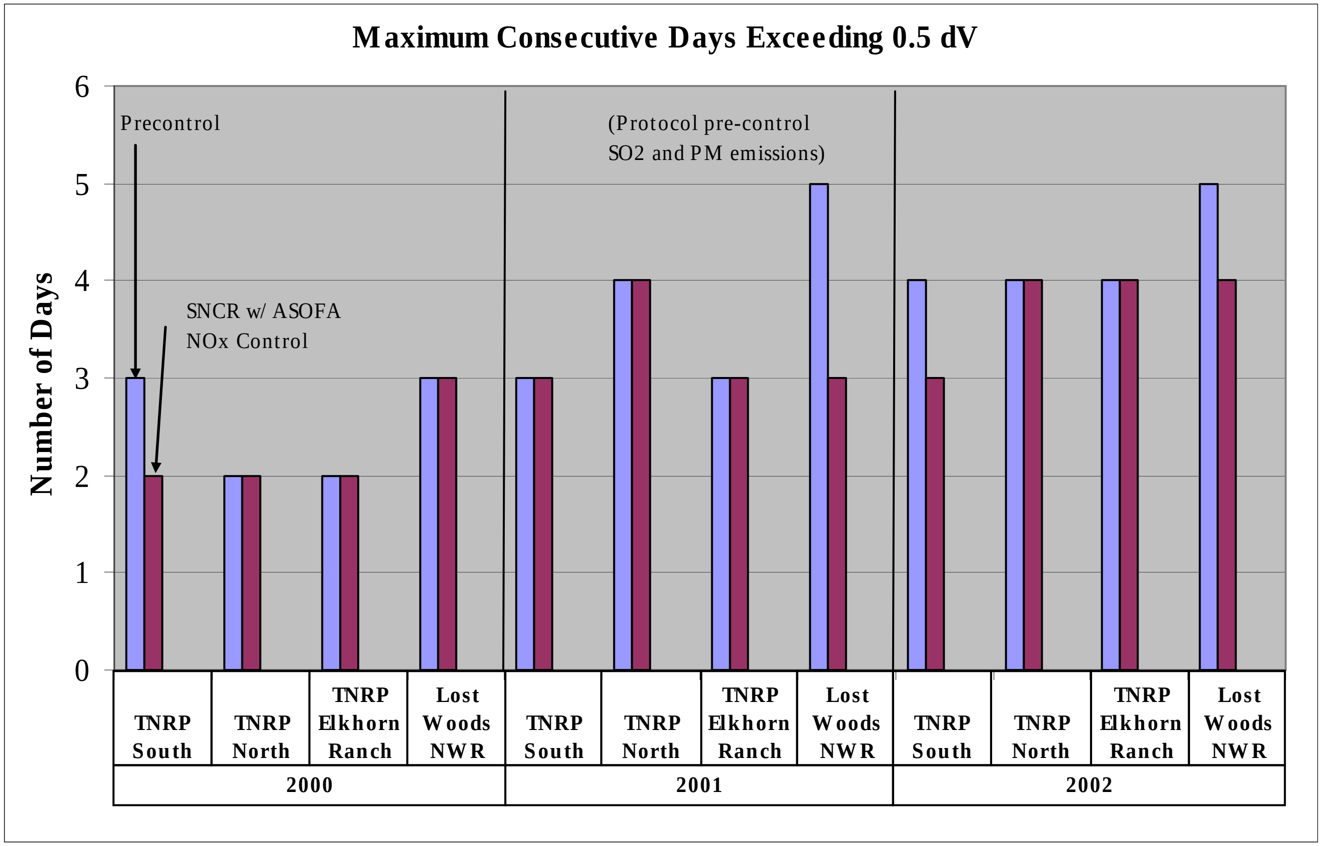


Figure 2.1-4 – Incremental Visibility Impairment Improvements – Days > 0.5 dV
SNCR w/ ASOFA BART NO_X Control vs Protocol Pre-Control NO_X Emissions
with Various Post-Control SO_2 and PM Emissions
MRYS Unit 1

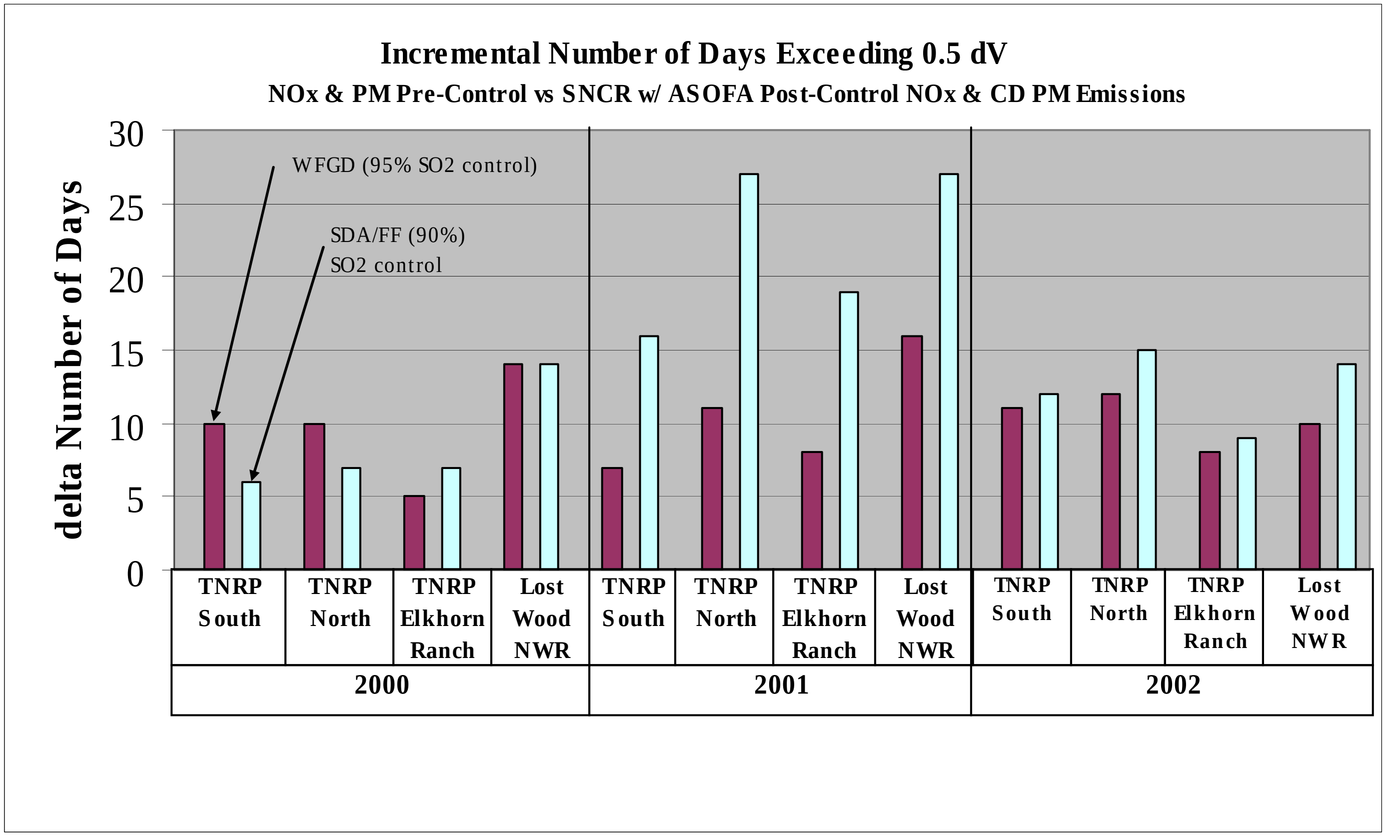


Figure 2.1-5 – Incremental Visibility Impairment Improvements – Days > 1.0 dV
SNCR w/ ASOFA BART NO_X Control vs Protocol Pre-Control NO_X Emissions
with Various Post-Control SO_2 and PM Emissions
MRYS Unit 1

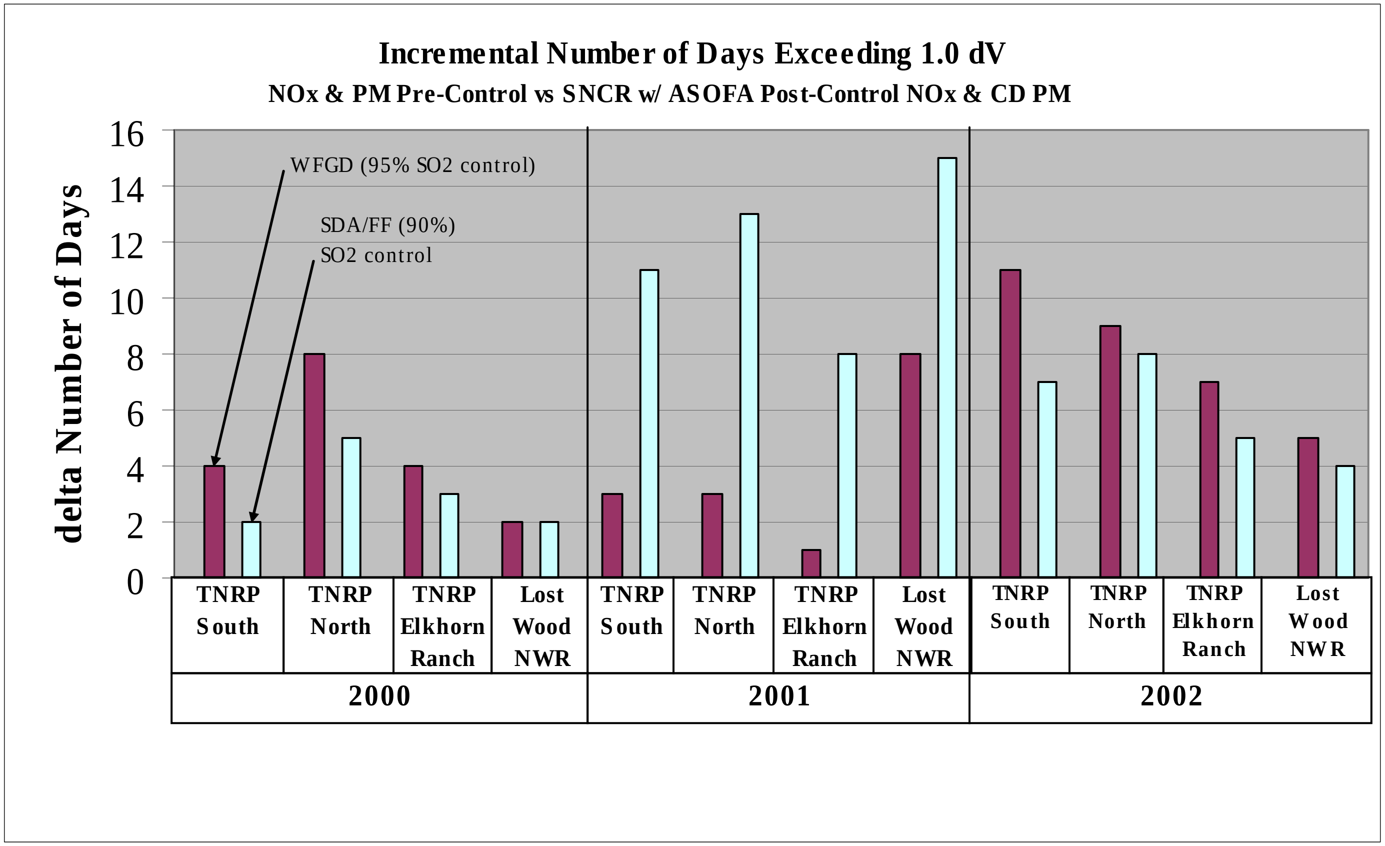


Figure 2.1-6 – Incremental Visibility Impairment Reductions – Maximum Consecutive Days Exceeding 0.5 dV SNCR w/ ASOFA BART NO_X Control vs Protocol Pre-Control NO_X Emissions with Various Post-Control SO_2 and PM Emissions MRYS Unit 1

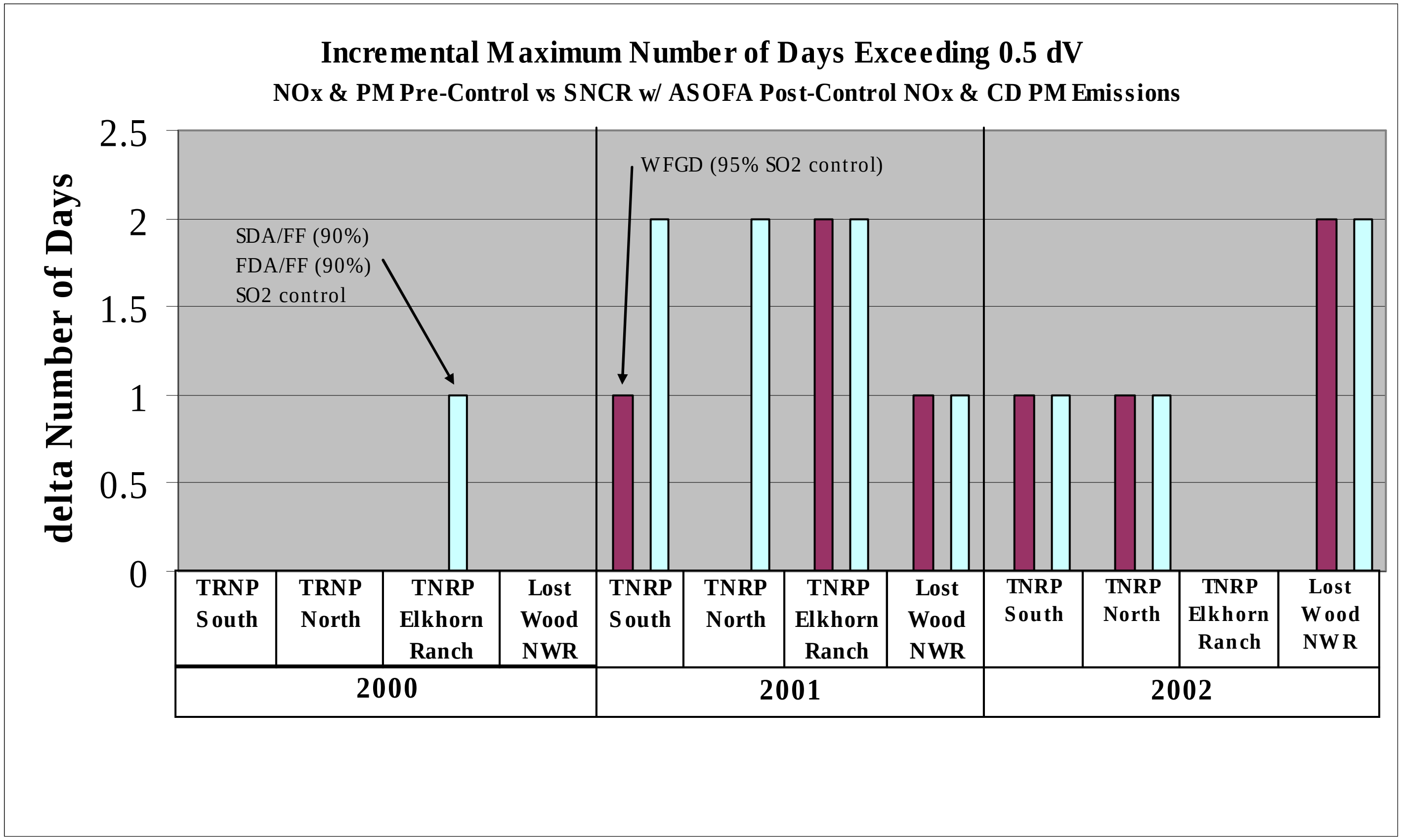


Figure 2.1-7 – Days of Visibility Impairment > 0.5 dV
SNCR w/ ASOFA BART NO_X Control with SO_2 and PM Controls
MRYS Unit 1

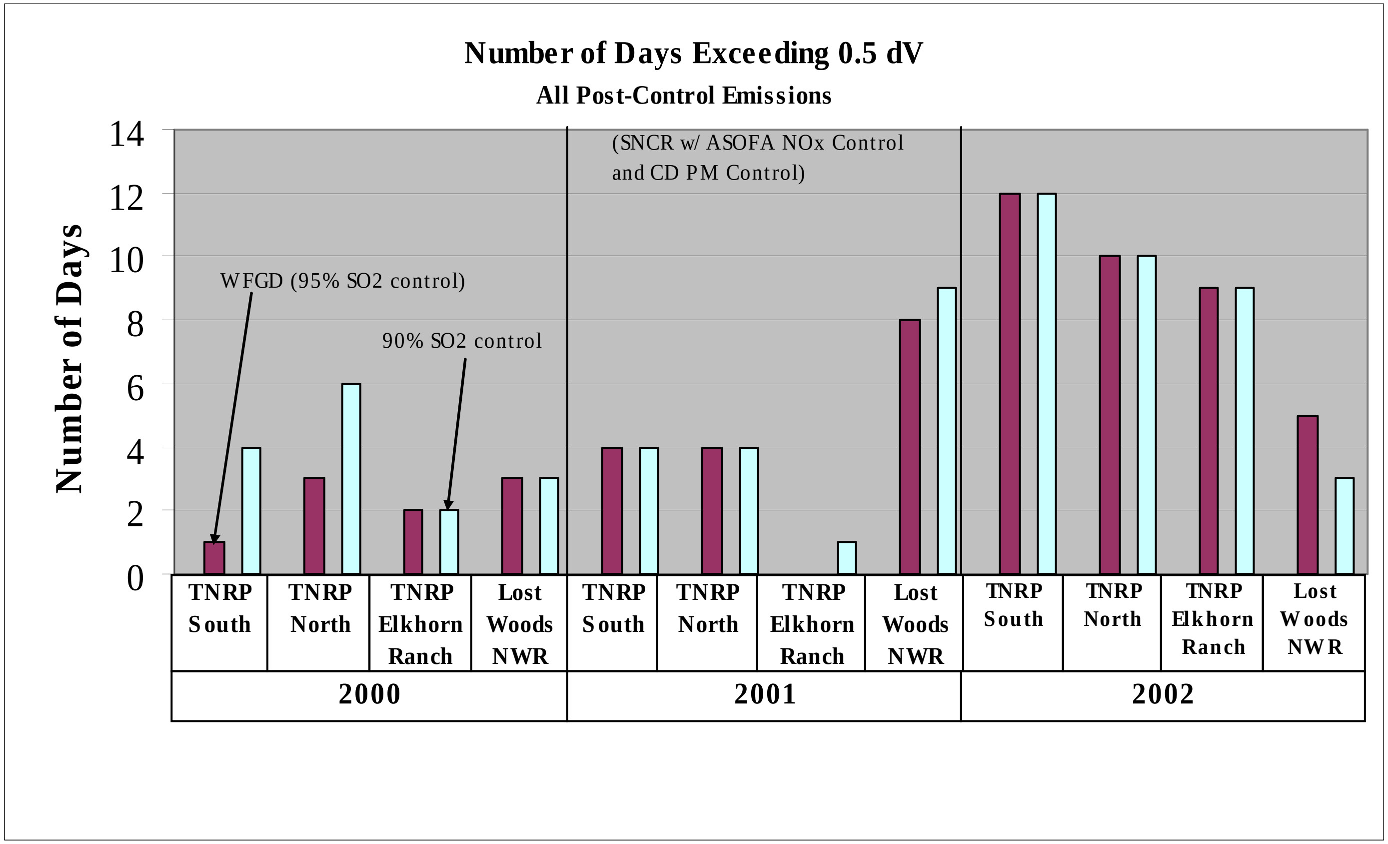


Figure 2.1-8 – Days of Visibility Impairment > 1.0 dV
SNCR w/ ASOFA BART NO_X Control with SO_2 and PM Controls
MRYS Unit 1

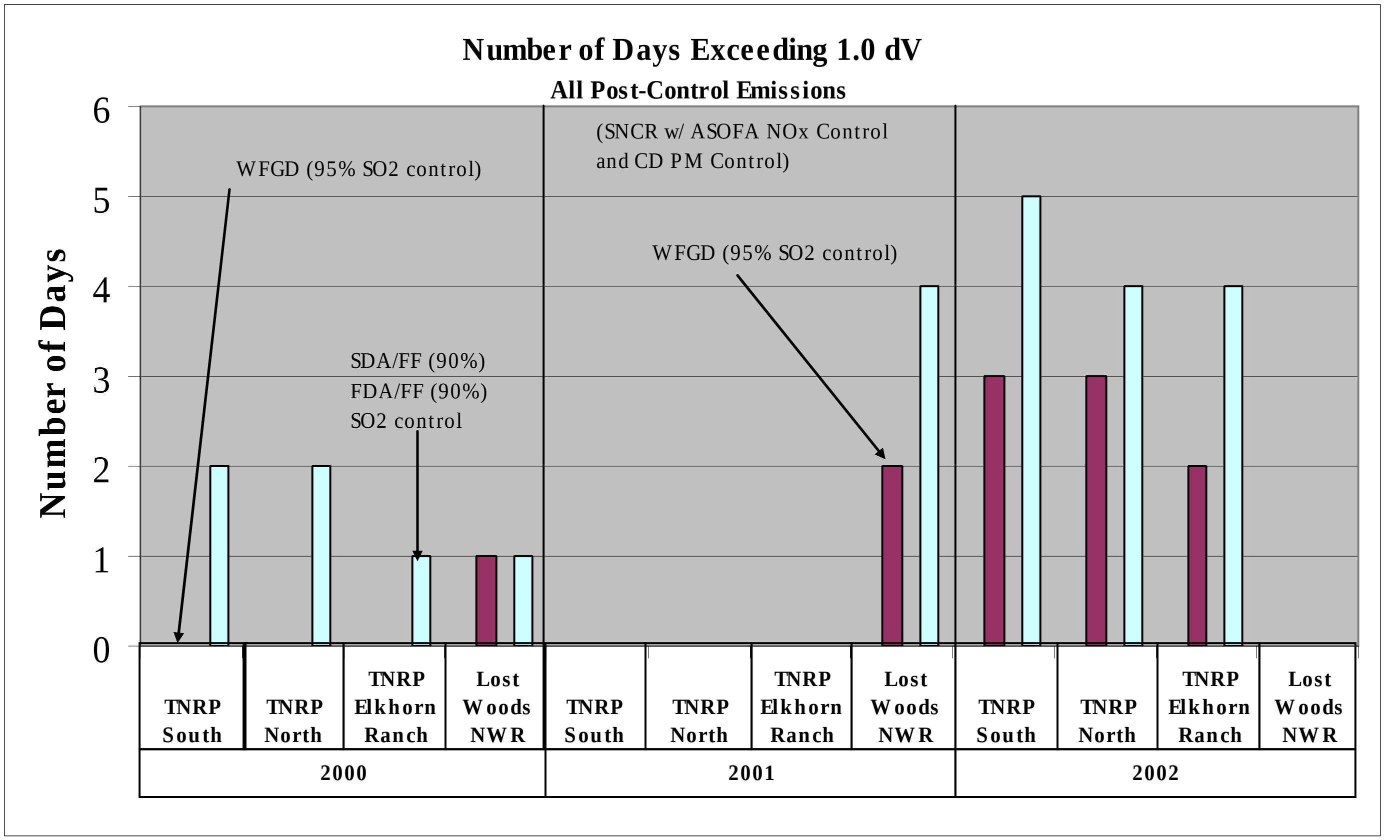
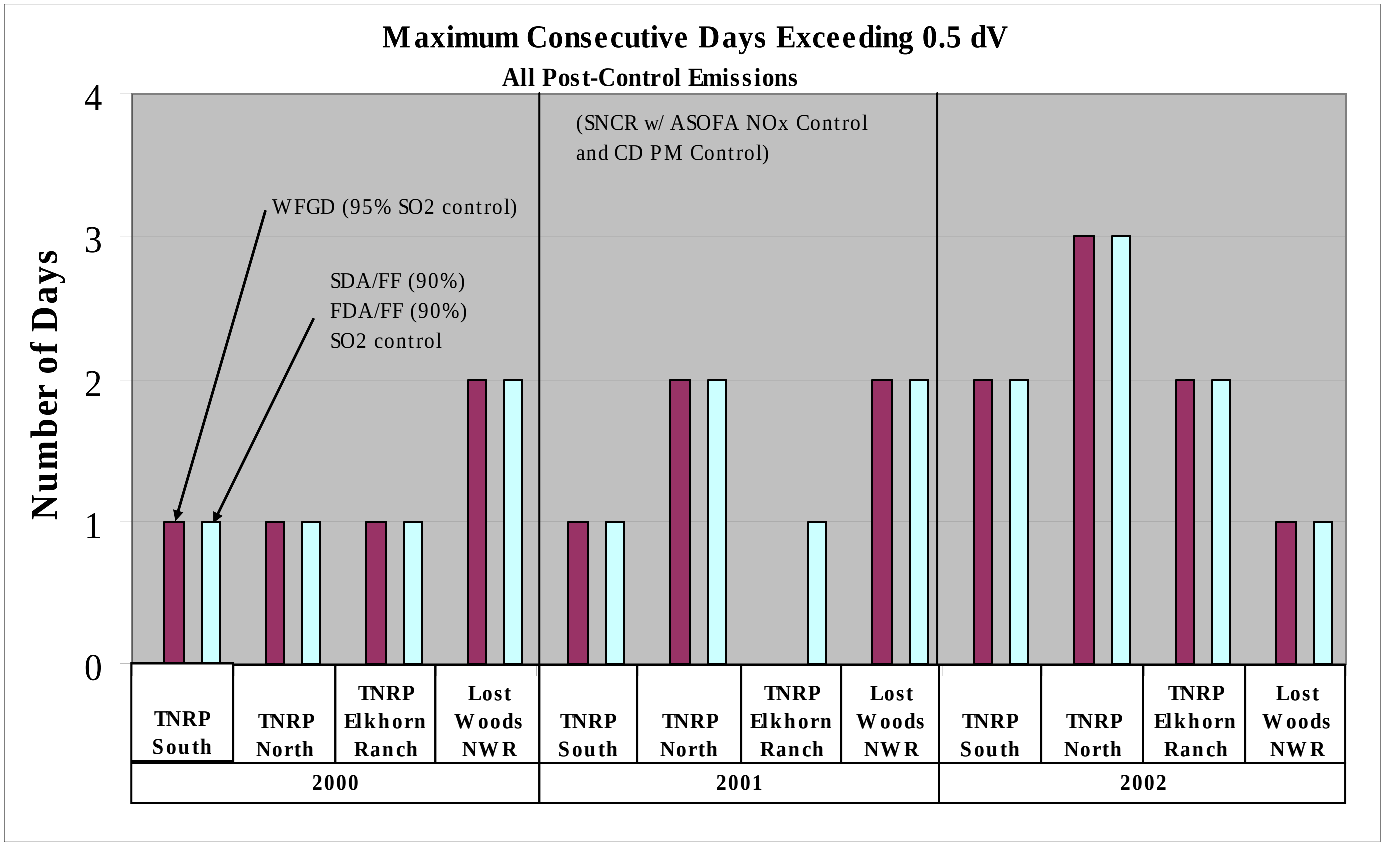


Figure 2.1-9 – Visibility Impairment Improvements – Reductions in Maximum Consecutive Days Exceeding 0.5 dV
SNCR w/ ASOFA BART NO_X Control with SO_2 and PM Controls
MRYS Unit 1



2.2 NO_X EVALUATION BASIS – UNIT 2

Milton R. Young Unit 2 is a Babcock and Wilcox steam generator installed in 1977. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation assisted with circulation pumps. Original unit design steam generating capacity is 3.20 million lbs/hr at 2,620 psi with a fuel heat input of 4,696 mmBtu/hr. The boiler is fired by twelve ten-foot diameter cyclone burners, arranged “three over three” across the front and rear walls of the lower furnace. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the ESP. Unit 2’s boiler serves a turbine-generator with a name plate rating of 477 MW[8], and has a nominal 439 MW net design output capacity rating. Unit 2 is capable of sustained output of approximately 462 MW gross, and has an ultimate short-term maximum gross output (URGE) of 512 MW. The Unit 2 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from a mine located adjacent to the site. This method of firing solid fuel significantly influences the resulting nitrogen oxide concentration of the flue gases emitted from the boiler.

2.2.1 NO_X VISIBILITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 2

The remaining step for the BART NO_X analysis was to conduct a visibility improvement determination for Unit 2. Due to the association of the Consent Decree and requisite BACT analysis, the visibility analysis was the only subsequent impact evaluation necessary to establish BART. In addition, because the BACT analysis resulted in one recommended control alternative, only one related emission rate was modeled to determine the visibility impairment impacts.

The modeling for Unit 2 uses two NO_X emission rates as a basis for the visibility impairment impacts. The NDDH BART protocol[9] NO_X emission rate of 5,364.2 lb /hr was modeled to determine a pre-control baseline visibility impact. This protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. This is equivalent to a unit NO_X emission rate of 0.894 lb/mmBtu at a boiler heat input rate of 5,999 mmBtu/hr. The baseline visibility impact was then compared with the result predicted from a modeled post-control NO_X emission rate based upon the control technology specified for Unit 2 in the BACT analysis. According to the BACT

[8] Ibid EPA’s eGRID database; April, 2003.
[9] Ibid NDDH Final BART Protocol; November, 2005.

analysis required by the Consent Decree, Selective Non-Catalytic Reduction (SNCR) used in conjunction with Advanced Separated Overfire Air (ASOFA) was considered the best technology and therefore was evaluated as BART for Unit 2. The second emission rate of 2,011.6 lb NO_X/hr was based upon application of SNCR and ASOFA control technologies for a reduction of approximately 62.5 percent from the protocol mass emission rate. This is equivalent to a unit NO_X emission rate of 0.390 lb/mmBtu at a more representative maximum 24-hour average boiler fuel heat input of 5,158 mmBtu/hr. The visibility modeling conditions are presented in Table 2.2-1.

Table 2.2-1 – Milton R. Young Station Unit 2 Visibility Model Conditions

	NDDH Protocol	SNCR with ASOFA(1)
NOx Emission Rate lb/hr	5,364.2	2,011.6
lb/mmBtu	0.894	0.390
Heat Input, mmBtu/hr	5,999.1	5,158.0

(1) – Post-control NO_X emission rate reflects recommended BACT w/ adjusted reduction.

The results of the visibility modeling at the protocol baseline NO_X emission rate for MRYS Unit 2 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for the post-control NO_X emission rate showed a reduction in visibility impairment impact for all Class 1 areas. In addition, the modeled visibility impairment impact for three of the Class 1 areas at the post-control BACT-level NO_X emission rate were below the 0.50 dV threshold level. The Lostwood NWR Class 1 area had a modeled visibility impairment impact of 0.543 dV. The modeling results are presented in Table 2.2-2.

Table 2.2-2 – NO_X Visibility Impairment Impacts and Reductions at NOx BACT Post-Control Emissions, MRYS Unit 2

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction (deciView)
	Protocol Emissions	Post-Control Emissions[2]	
TRNP-South Unit	0.580	0.406	0.174
TRNP-North Unit	0.619	0.438	0.181
TRNP-Elkhorn Ranch	0.360	0.278	0.082
Lostwood NWR	0.775	0.543	0.232

1 - Average 90^{th} percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.5-1 and the modeling results are presented in Appendix A.

2 - NO_X emissions reduction by 62.5% over NDDH protocol baseline case. This scenario assumes protocol emission rates for SO_2 and PM. Refer to Appendix A for complete protocol and revised post-control visibility model results.

The number of days predicted to have visibility impairment due to MRYS Unit 2 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol emission rates. The results are summarized and presented in Table 2.2-3. Similarly, the same information for the post-control NO_X emission rates is summarized and shown in Table 2.2-3. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control NO_X emission rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 areas, for Unit 2. The impact in terms of days exceeding 0.50 dV varies from an approximately 9% reduction for TRNP – Elkhorn in 2001 to an approximately 37% reduction for TRNP – South in 2000. The impact reduction in terms of days exceeding 1.00 dV varies from approximately 15% for TRNP – Elkhorn in 2002 to approximately 50% for TRNP – North in 2000.

A series of bar charts showing the difference in the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for the SNCR with ASOFA-controlled post-control emission rates with pre- and post-control SO_2 and PM alternatives is included in Figures 2.2-1 through 2.2-9.

Table 2.2-2 – Visibility Impairment Improvements for NOx BACT Post-Control Emissions – MRYS Unit 2 NO_X Scenarios

Class 1 Area	NO_X Control Technique	Days[1] Exceeding 0.5 dV in 2000	Days[1] Exceeding 0.5 dV in 2001	Days[1] Exceeding 0.5 dV in 2002	Days[1] Exceeding 1.0 dV in 2000	Days[1] Exceeding 1.0 dV in 2001	Days[1] Exceeding 1.0 dV in 2002	Consecutive Days[1] Exceeding 0.5 dV 2000	Consecutive Days[1] Exceeding 0.5 dV 2001	Consecutive Days[1] Exceeding 0.5 dV 2002
TRNP South	Protocol	41	28	51	18	14	27	3	3	4
	SNCR w/ ASOFA	26	20	40	11	11	21	2	3	3
TRNP North	Protocol	32	43	47	18	21	29	2	4	4
	SNCR w/ ASOFA	24	32	40	9	13	23	2	4	4
TRNP Elkhorn	Protocol	31	23	36	11	14	20	2	3	4
	SNCR w/ ASOFA	22	21	30	7	10	17	2	3	4
Lostwood NWR	Protocol	52	51	48	30	31	25	3	3	5
	SNCR w/ ASOFA	41	39	34	19	22	20	3	3	4

1 - Number of days for predicted visibility impairment impacts provided in Appendix A.

Figure 2.2-1 – Reduction in Days of Visibility Impairment > 0.5 dV
SNCR w/ ASOFA BART NO_X Control with Protocol Pre-Control SO_2 and PM Emissions
MRYS Unit 2

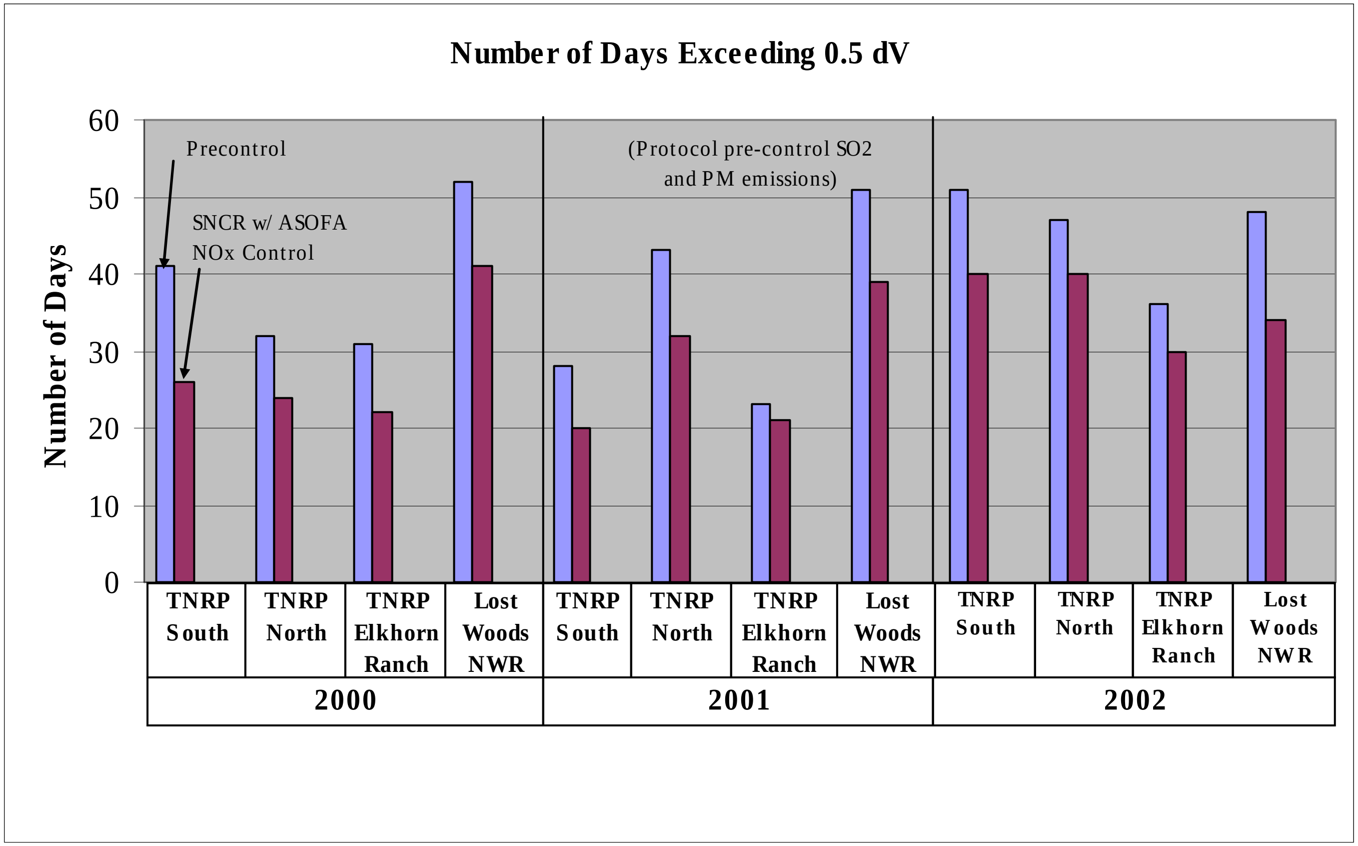


Figure 2.2-2 – Reduction in Days of Visibility Impairment > 1.0 dV
SNCR w/ ASOFA BART NO_X Control with Protocol Pre-Control SO_2 and PM Emissions
MRYS Unit 2

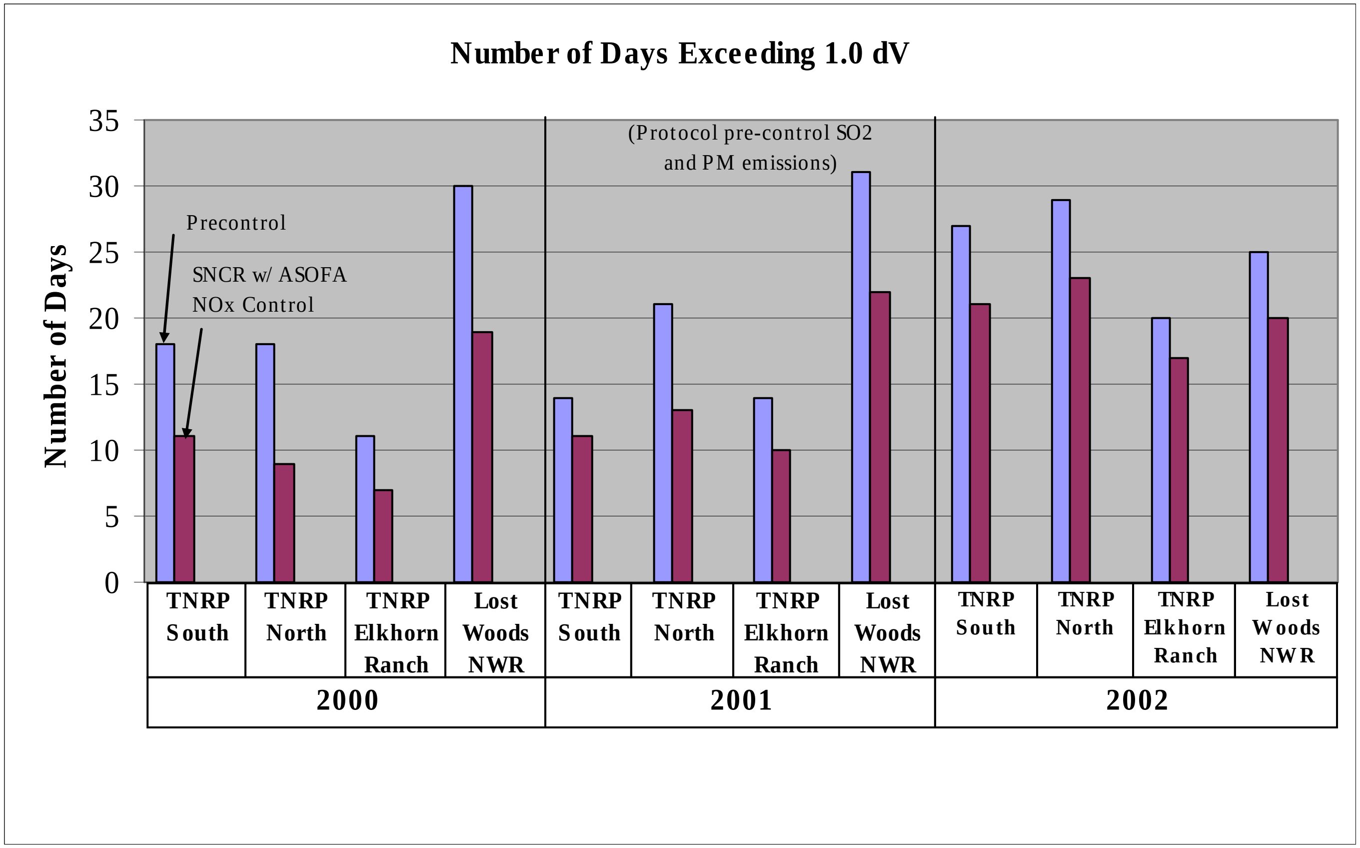


Figure 2.2-3 – Reduction in Maximum Consecutive Days Exceeding 0.5 dV
SNCR w/ ASOFA BART NO_X Control with Protocol Pre-Control SO_2 and PM Emissions
MRYS Unit 2

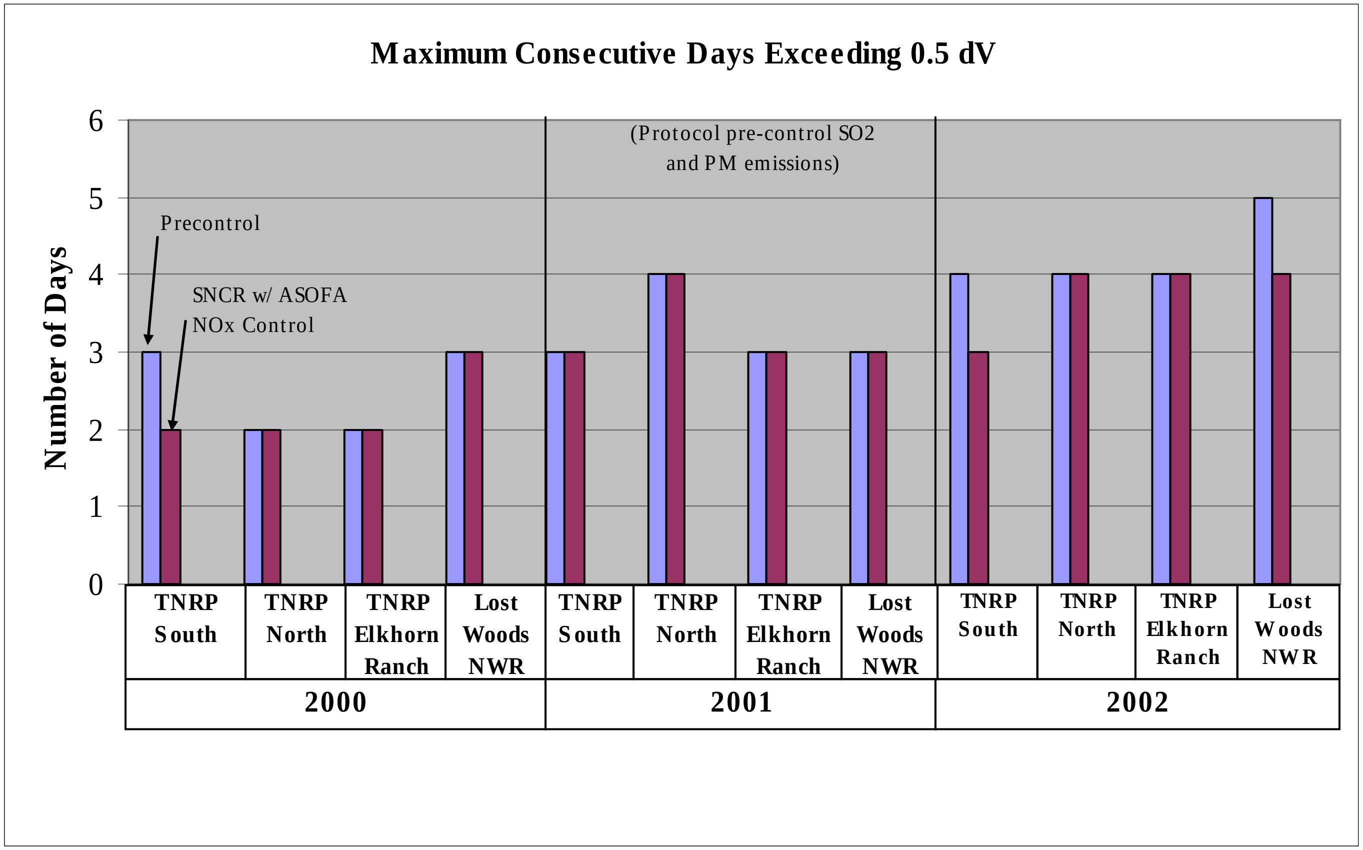


Figure 2.2-4 – Incremental Visibility Impairment Improvements – Days > 0.5 dV
SNCR w/ ASOFA BART NO_X Control vs Protocol Pre-Control NO_X Emissions
with Various Post-Control SO_2 and PM Emissions
MRYS Unit 2

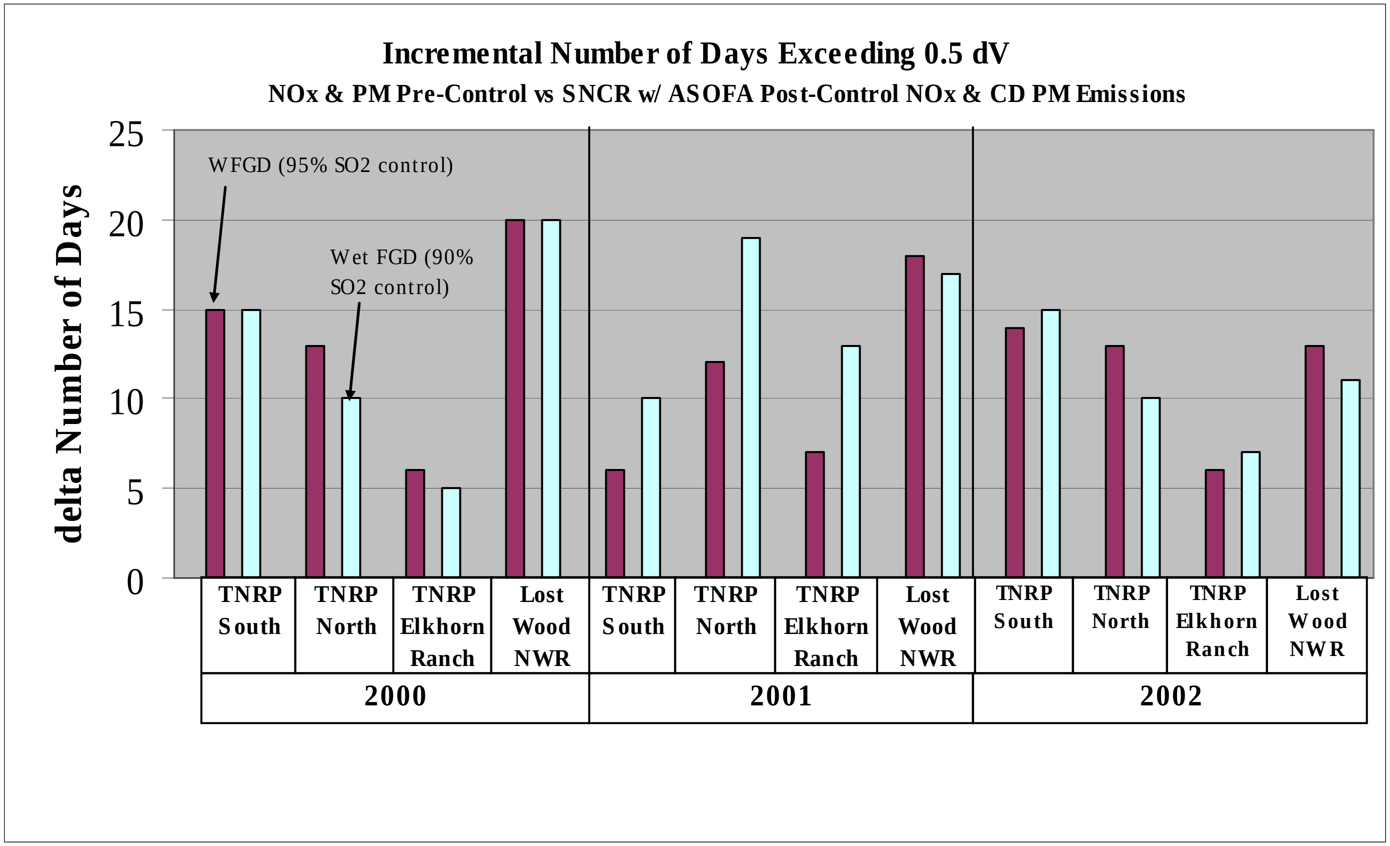


Figure 2.2-5 – Incremental Visibility Impairment Improvements – Days > 1.0 dV
SNCR w/ ASOFA BART NO_X Control vs Protocol Pre-Control NO_X Emissions
with Various Post-Control SO_2 and PM Emissions
MRYS Unit 2

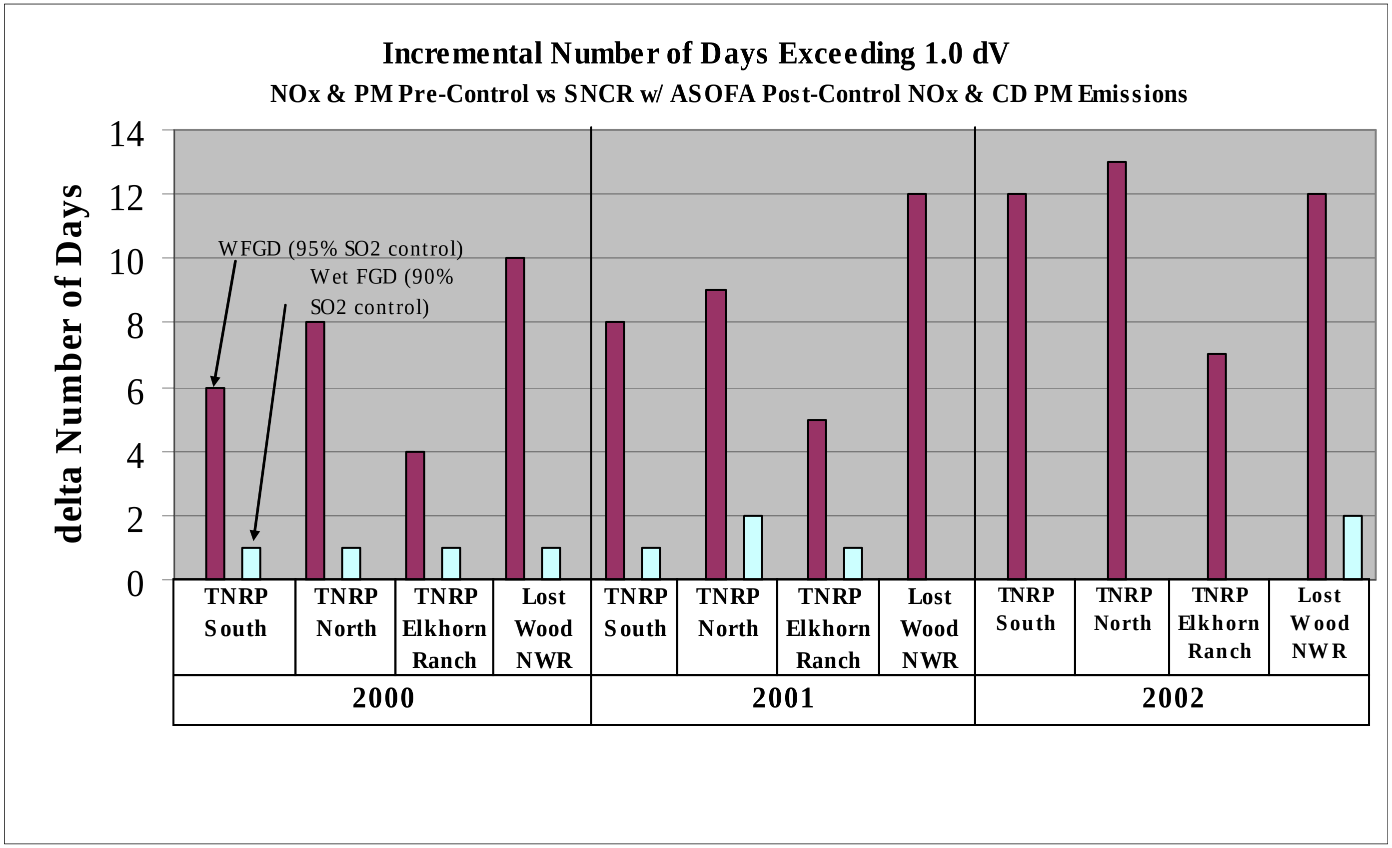


**Figure 2.2-6 – Incremental Visibility Impairment Reductions – Maximum Consecutive Days Exceeding 0.5 dV
SNCR w/ ASOFA BART NO_X Control vs Protocol Pre-Control NO_X Emissions
with Various Post-Control SO_2 and PM Emissions
MRYS Unit 2**

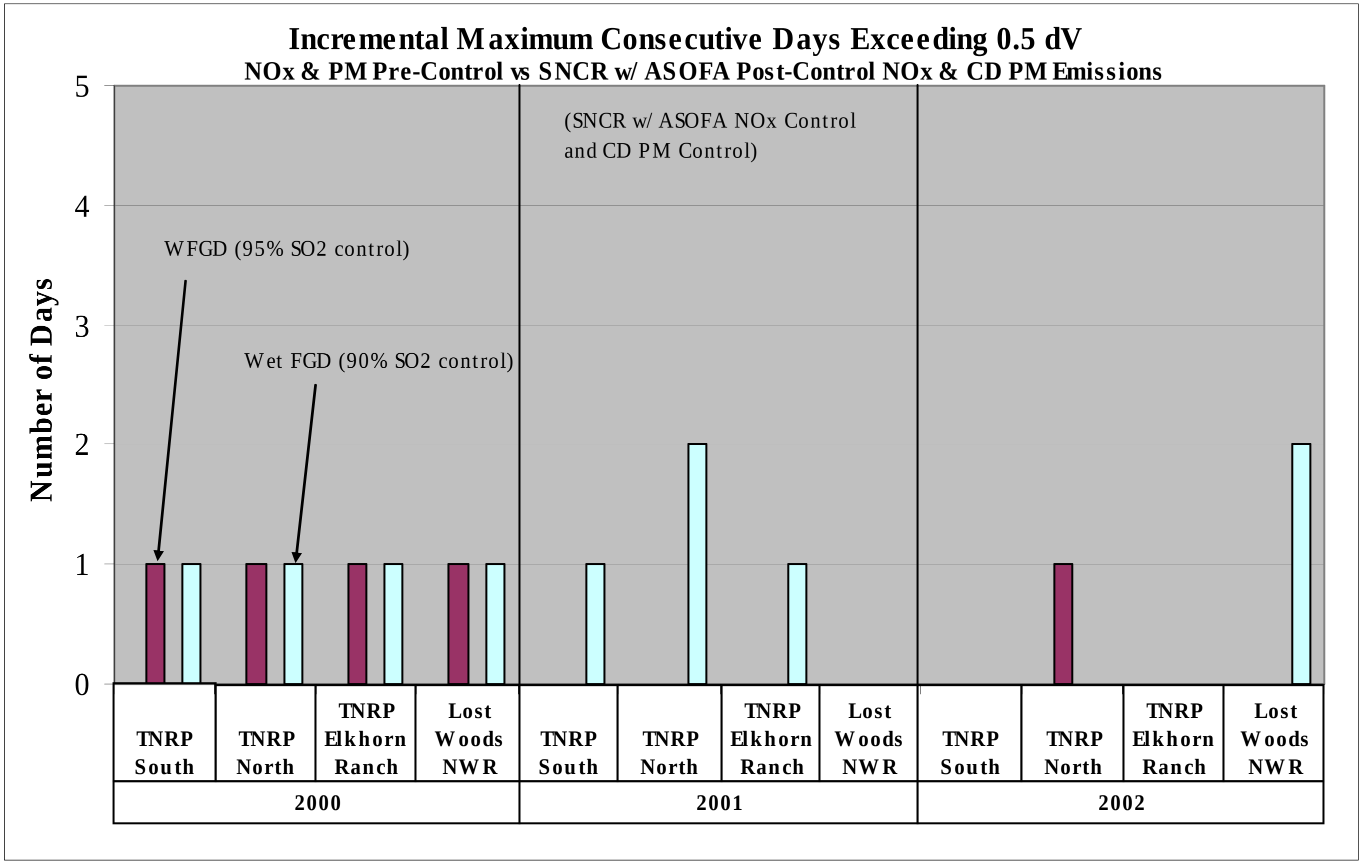


Figure 2.2-7 – Reduction in Days of Visibility Impairment > 0.5 dV
SNCR w/ ASOFA BART NO_X Control with SO_2 and PM Controls
MRYS Unit 2

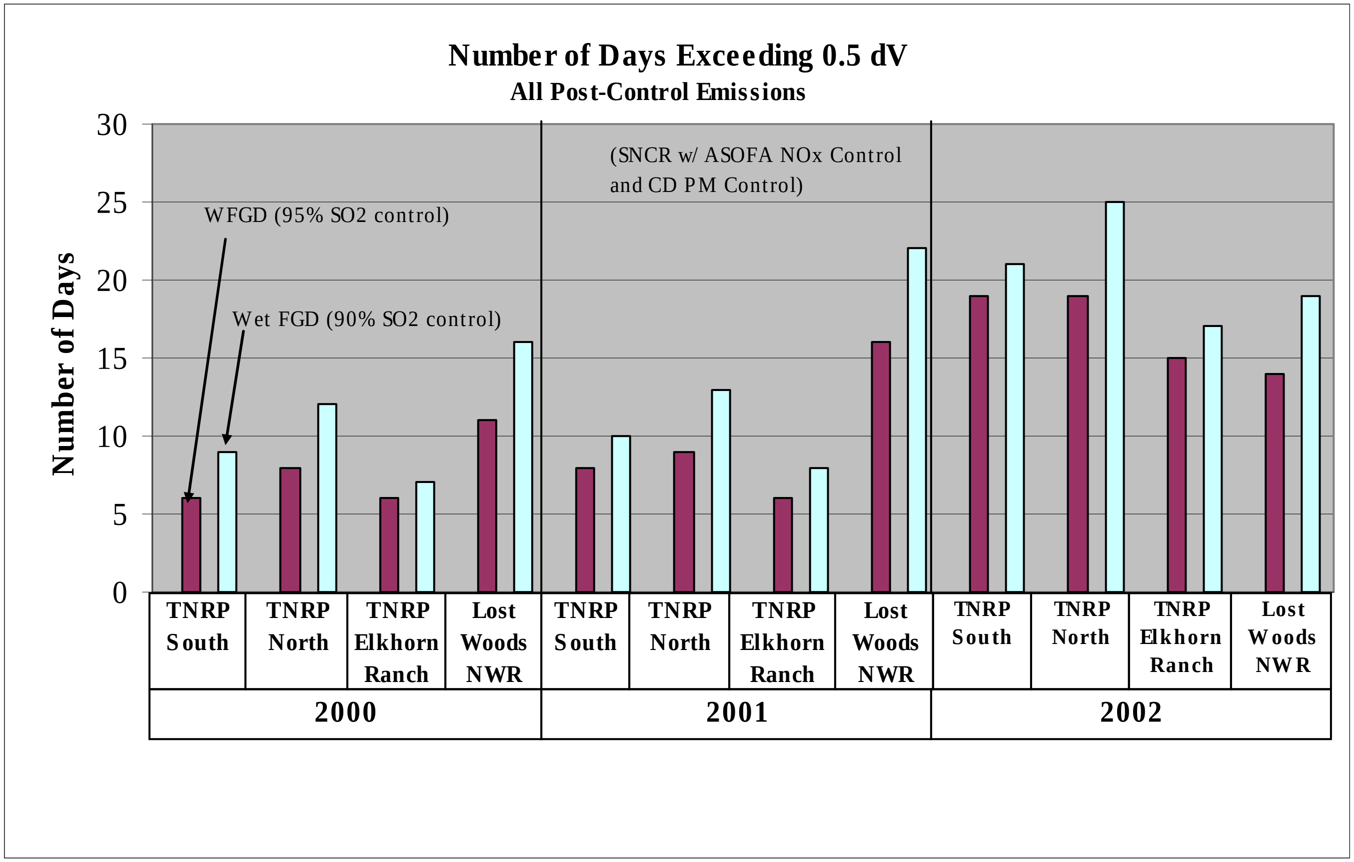


Figure 2.2-8 – Reduction in Days of Visibility Impairment > 1.0 dV
SNCR w/ ASOFA BART NO_X Control with SO_2 and PM Controls
MRYS Unit 2

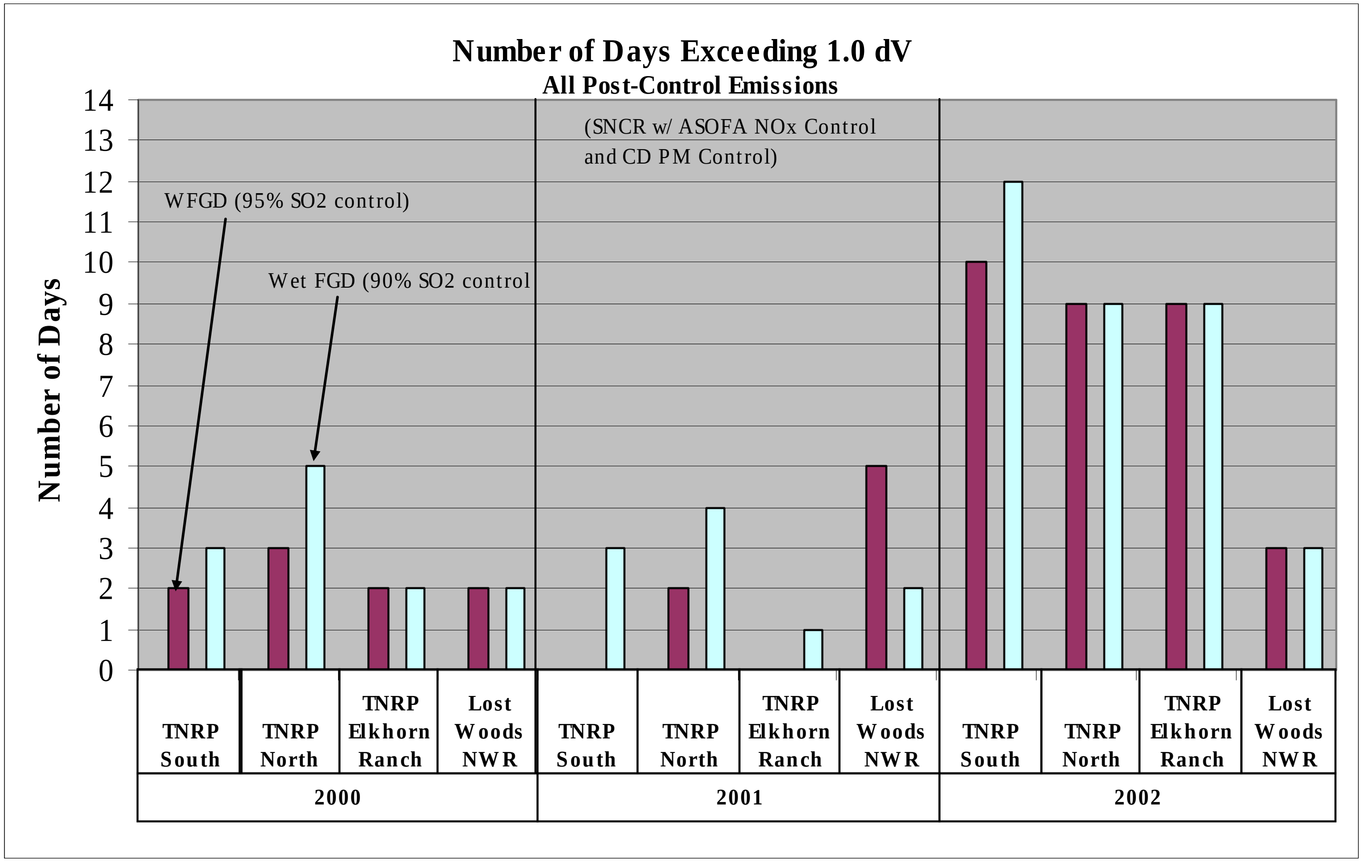
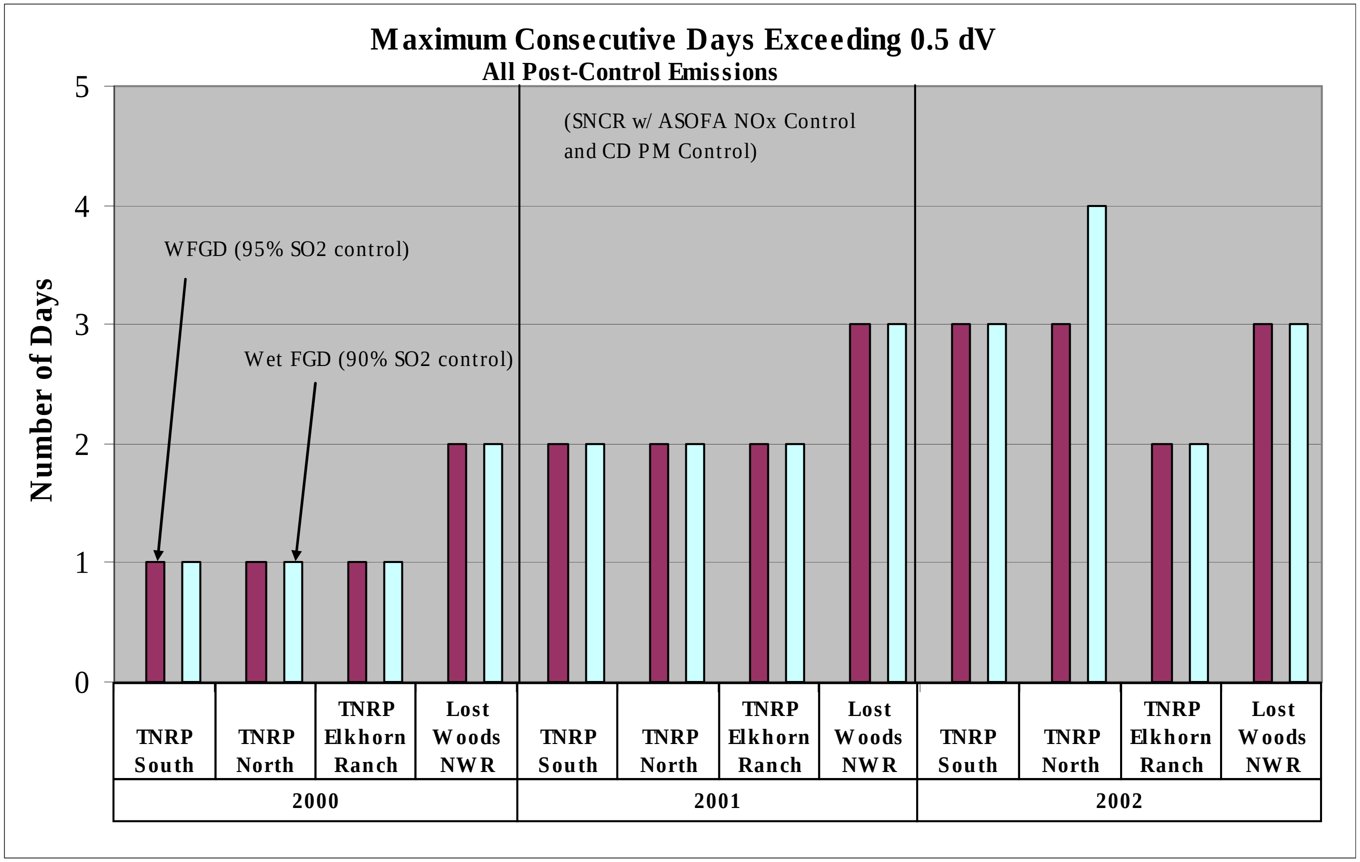


Figure 2.2-9 – Visibility Impairment Improvements – Reductions in Maximum Consecutive Days Exceeding 0.5 dV
SNCR w/ ASOFA BART NO_X Control with SO_2 and PM Controls
MRYS Unit 2



3.0 SO_2 BART EVALUATION

The BART determination process has five predefined steps as described in Section 1. In this section, steps 1 through 5 of the BART determination for Milton R. Young Station (MRYS) are described for SO_2 and a presentation is made of the results. Potentially applicable SO_2 control technologies are first identified. A brief description of the processes and their capabilities are then reviewed for availability and feasibility. A detailed technical description of each control technology is provided in Appendix B. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to nominal SO_2 control capability. The impacts analysis then reviews the estimated capital and O&M costs for each alternative. Following the cost determination, the energy impacts and non-air quality impacts are reviewed for each technology. The impact based on the remaining useful life of the source is reviewed as part of the cost analysis. In the final step of the analysis, feasible and available technologies are assessed for their potential visibility impairment impact reduction capability via visibility modeling results. The results of the impact analyses are tabulated and potential BART control options are listed.

3.1 IDENTIFICATION OF RETROFIT SO_2 CONTROL TECHNOLOGIES

The initial step in the BART determination is the identification of retrofit SO_2 control technologies. In order to identify the applicable SO_2 control technologies, several reference works were consulted, including "Controlling SO_2 Emissions: A Review of Technologies (EPA-600/R-00-093, October 2000) and the RACT/BACT/LAER Clearinghouse (RLBC). From these and other literature sources, a preliminary list of control technologies and their estimated capabilities for potential application to MRYS was developed. However, as discussed in the introduction, Minnkota has entered into a Consent Decree (CD) that requires MRYS to install or modify SO_2 control technologies on both units to achieve emission rates that do not exceed specified levels. The Consent Decree defines the minimum levels of SO_2 control removal efficiencies applicable for technology installation options on MRYS Unit 1 and requires that the existing wet FGD process be upgraded to maintain a 30-day rolling average SO_2 removal efficiency of ninety percent (90%) for Unit 2. Thus, the control technologies included in the BART analysis either meet the minimum level of control specified by the CD or have more stringent removal efficiency. Table 3.1-1 contains the results of this effort.

TABLE 3.1-1 – SO_2 Control Technologies Identified for BART Analysis

Control Technology	Approximate Control Efficiency
Wet Flue Gas Desulfurization (FGD)	95%
Dry Flue Gas Desulfurization (FGD)	90%
Powerspan ECO™	98%

3.2 TECHNICAL DESCRIPTION AND FEASIBLITY ANALYSIS

The second step in the BART analysis procedure is a technical feasibility analysis of the options identified in Step 1. The BART guidelines discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the "availability" and "applicability" of each control technology. A control technology is considered available, "if it has reached the stage of licensing and commercial availability." (70 FR 39165) On the contrary, a control technology is not considered available, "if it is in the pilot scale testing stages of development." (70 FR 39165) When considering a source's applicability, technical judgment must be exercised to determine "if it can reasonably be installed and operated on the source type." (70 FR 39165) The technical and feasibility analysis is presented below for each identified option.

3.2.1 WET FLUE GAS DESULFURIZATION

Wet FGD technology utilizing lime or limestone as the reagent is commonly applied to coal-fired boilers. Wet FGD utilizes am absorber, such as an open spray tower or a spray tower with a perforated plate contactor, to expose flue gas to the neutralizing slurry. Absorbed SO_2 is converted to calcium sulfite and then may be oxidized to calcium sulfate dihydrate (gypsum) which is filtered from the scrubber solution and either disposed of in a permitted disposal facility, or possibly sold for either wallboard or cement production. Lime is utilized as the reagent in the wet FGD technology analysis, because the plant currently uses lime in the Unit 2 FGD process, has existing lime reagent preparation equipment, and because limestone availability is limited in North Dakota. Note that although existing reagent preparation equipment is available, a new system is required to supply sufficient volume for controlling both EGUs.

Historically, wet FGD systems have operated with SO_2 control efficiency anywhere from 70% to 95%. Several new coal-fired power plant projects such as Thoroughbred, Trimble County and Mustang have been proposed with SO_2 control efficiency of 98 percent. However, the "EPA has concluded that 98 percent control is possible with certain control and boiler configurations under ideal conditions. The amended standard for SO_2 is based on a 30-day average that includes the variability that occurs from non-ideal operating conditions". This comes from the NSPS "Standards of Performance for Electric Utility Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units; Final Rule" recently promulgated by EPA as final rule amendments to 40 CFR part 60, subparts Da, Db, and Dc emission standards effective February 27, 2006[10]. Achieving ideal operating conditions such that an average 98% level of SO_2 emissions control could be sustained for every 30-day rolling period has not been demonstrated by the new power projects mentioned. For the purposes of this analysis, wet FGD performance was evaluated at 95% SO_2 control as representative of presumptive BART requirements. Further technical characteristics associated with wet FGD are described in Appendix B.

Based on the ability of a wet FGD system to achieve 95 percent SO_2 removal efficiencies and commercial availability and applicability, wet FGD systems were found to be an acceptable BART alternative for MRYS Unit 1's SO_2 emission control.

This report evaluates the wet FGD process currently operating on Unit 2 as a possible BART alternative. The existing wet FGD system currently treats approximately 78 percent of the flue gas with the remaining flue gas by-passed for stack gas reheat and achieves approximately 75 percent SO_2 removal. However, the Consent Decree requires that the existing wet FGD process be upgraded to maintain a 30-day rolling average SO_2 removal efficiency of ninety percent (90%) for Unit 2. Thus, the wet FGD process is evaluated at 90% SO_2 removal efficiency. Because some wet FGD systems are capable of achieving 95% control, modifications required to increase the removal efficiency of the existing wet FGD process to 95% is also evaluated as BART for Unit 2. Note that although 95% removal efficiency is evaluated as part of this analysis, a detailed engineering analysis is required to determine if the existing wet FGD process can be modified to achieve 95% control and is not included in the scope of this report.

3.2.2 DRY FLUE GAS DESULFURIZATION

As an alternative to wet FGD technology, the control of SO_2 emissions can be accomplished using dry FGD technology. The most common dry FGD system is the lime Spray Dryer Absorber (SDA) using a fabric filter for downstream particulate collection. There are several variations of the dry process in use today. This section addresses the spray dryer FGD process. Two other variations, the Flash Dryer

[10] Federal Register /Vol. 71, No. 38, page 9870.

Absorber (FDA) and Circulating Dry Scrubber (CDS) are similar in nature. They primarily differ by the type of reactor vessel used, the method in which water and lime are introduced into the reactor and the degree of solids recycling. Technical characteristics associated with the SDA, FDA and CDS are described in Appendix B.

No variation of dry FGD systems has clearly demonstrated the ability to achieve SO_2 removal levels similar to wet FGD systems in the U.S. Two units were recently permitted with SO_2 emission rates representing removal efficiencies of 94.5% and 95%. However, Burns & McDonnell recently completed a study of the emission reduction performance of existing, electric utility, dry FGD systems.[11] Information utilized for the evaluation was derived from EIA coal quality data and EPA SO_2 stack emissions and heat input data. The evaluation determined that the highest SO_2 removal efficiency maintained on a continuous basis was just above 90%. No dry FGD unit was able to maintain an average efficiency of 95% for continuous 30-day rolling periods. For the purpose of this BART determination, dry FGD is considered a viable alternative for Unit 1, but the upper bound on SO_2 removal efficiency was set at 90% based on a review of the historic performance of this technology.

3.2.3 POWERSPAN ELECTRO-CATALYTIC OXIDATION TECHNOLOGY

The Powerspan Electro-Catalytic Oxidation (ECO™) system is a multipollutant control technology designed to control emissions of NO_X, SO_2, fine particulate, mercury and certain Hazardous Air Pollutants (HAPs). The ECO™ process has two main process vessels; a barrier discharge reactor and a multi-level wet scrubber. Additional technical characteristics associated with the ECO™ process are described in Appendix B.

Powerspan claims a routine SO_2 removal efficiency of 98% with inlet concentrations up to approximately 2,000 ppm and testing at a pilot plant has demonstrated performance, reliability and economics. However, no full size commercial scale ECO™ systems have been installed or are operating at the time of this report. The ECO system was determined not to be a feasible BART alternative because it is not commercially available.

[11] SO_2 Removal Efficiency Achieved in Practice by U.S. Electric Utility Semi-Dry FGD Systems"; Electric Utility Environmental Conference (EUEC); Weilert, C. and Randall, D.; Tucson, AZ; January 2006.

3.2.4 RESULTS OF FEASIBILITY ANALYSIS

The evaluations of the identified BART alternatives following the feasibility analysis are summarized in Table 3.2-1.

TABLE 3.2-1 – MRYS BART SO_2 Control Feasibility Analysis Results

Control Technology	In full-scale service on Existing Utility Boilers	In Service on Other Combustion Sources	Commercially Available	Technically Applicable To Milton R. Young Station
Wet FGD	Yes	Yes	Yes	Yes
Dry FGD	Yes	Yes	Yes	Yes
Powerspan ECO™	No	No	No	Yes

3.3 EVALUATE TECHNICALLY FEASIBILE SO_2 CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis procedure is to evaluate the control effectiveness of the technically feasible alternatives. During the feasibility determination in step 2 of the BART analysis, the SO_2 control efficiency was reviewed and presented as part of the technical description for each technology. The evaluations of the remaining BART alternatives following the feasibility analysis are summarized in Table 3.3-1. The alternatives are ranked in descending order according to their effectiveness in SO_2 control.

TABLE 3.3-1 – Feasible SO_2 Control Technologies Identified for BART Analysis

Control Technology	Unit 1	Unit 2
Wet FGD	95% Control	90% and 95% Control
Dry FGD	90% Control	NA*

*Dry FGD is not evaluated for Unit 2 because the existing wet FGD can be used to achieve equivalent removal efficiency while using existing equipment.

3.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS – UNIT 1

Step four in the BART analysis procedure is the impact analysis. The BART Determination Guidelines (70 FR 39166) lists four factors to be considered in the impact analysis.

- The costs of compliance;
- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

Three of the four impacts required by the BART Guidelines are discussed in the following sections. The remaining useful life of the source was determined to be greater than the project life definition in the EPA's OAQPS Control Cost Manual (EPA/453/B-96-001) and thus had no impact on the BART determination for MRYS. In addition, as described in Section 1.4, the visibility impairment impact of each alternative was evaluated as part of the impact analysis.

3.4.1 COST ESTIMATES

Cost estimates for the wet and dry SO_2 control technologies were completed utilizing the Coal Utility Environmental Cost (CUECost) computer model (Version 1.0) available from the U.S. Environmental Protection Agency and engineering estimates based upon Burns & McDonnell's in-house experience. The CUECost model is a spreadsheet-based computer model that was specifically developed to estimate the cost of air pollution control technologies for utility power plants within +/- 30 percent accuracy. The EPA released the version of the model used for this study in February 2000. The model is available for download from the U.S. EPA website at www.epa.gov/ttn/catc/products. Operating information utilized as input into the model for the purpose of cost estimating is presented in Appendix C. Economic information utilized as input into the model is given in Table 1.2-1.

3.4.1.1 WET FGD CAPITAL COST ESTIMATE

The capital cost estimate for the wet FGD system includes the SO_2 control system, major support facilities and BOP costs. The SO_2 control system cost is representative of a typical furnish and erect contract by a wet FGD system supplier. The wet FGD system cost estimated by CUECost is broken down into the major subsystems of reagent preparation, SO_2 absorption tower, dewatering systems, flue gas handling systems (new ID fans and ductwork) and support systems. BOP costs are described below in more detail.

The addition of a wet FGD absorber to Unit 1 will require a wet stack to exhaust the flue gas. The existing Unit 1 stack is in poor physical condition and is not sufficient for wet stack operations. Although not designed for wet stack operations, it would however be possible to reuse the existing Unit 2 stack to exhaust the flue gas from Unit 1. To make the Unit 2 stack suitable for wet stack operation, the existing liner would either have to be demolished and replaced with an alloy-clad liner or it would have to be lined from the stack breeching upwards with a corrosion resistant material such as alloy wallpaper or Penngard block or similar coating. A stack drain system would be required to collect and remove moisture dropout from the flue gas. BOP costs include modifications to the existing Unit 2 stack for wet stack operation, long lengths of ductwork to the Unit 2 stack inlet, and electrical subcontract. The results of the capital cost estimate are given in Table 3.4-1.

Table 3.4-1 – Capital Cost Estimate for MRYS Unit 1 Wet Lime FGD System

DIRECT COSTS	Estimated Cost ($2,006)	General Facilities Markup (10%)	Total Direct Cost
Wet Lime FGD System			
Reagent Prep System	$15,748,000	$1,575,000	$17,323,000
SO_2 Absorption System	$25,640,000	$2,564,000	$28,204,000
Flue Gas Handling System	$10,185,000	$1,019,000	$11,204,000
Byproduct Handling System	$504,000	$50,000	$554,000
Support Equipment	$2,538,000	$254,000	$2,792,000
		Wet Lime Total Direct Cost =	**$60,077,000**
BOP Costs			
Electrical Subcontract	$8,055,000	NA	$8,055,000
Stack Modifications	$9,783,000	NA	$9,783,000
Additional Ductwork	$1,364,000	NA	$1,364,000
		BOP Total Direct Cost =	**$19,202,000**
		Total Direct Cost =	**$79,278,000**
INDIRECT COSTS			
		Contingency (20% of DC)	$15,856,000
		A/E Engineering and Construction Management (10% of DC)	$7,928,000
		Prime Contractor's Fee (3% of DC)	$2,378,000
		Allowance For Funds During Construction (AFDC 3.8%)	$3,013,000
		Indirect Cost Subtotal	$29,174,000
		Total Plant Investment (TPI)	**$108,452,000**
		Pre-Production Costs	$3,108,000
		Inventory	$215,000
		Total Capital Requirement	**$111,776,000**

The CUECost estimating model includes a cost estimate for a wet stack, but this estimate was deleted from the model results and a revised estimate by Burns & McDonnell was included in the BOP costs for modifications to the existing Unit 2 stack. The estimate includes the demolition of the existing stack liner and installation of a new C-276 clad liner and provisions for stack icing mitigation.

The total estimated capital cost estimate for a complete, stand-alone wet FGD system utilizing lime reagent is $111,776,000, or $430/kW.

3.4.1.2 DRY FGD CAPITAL COST ESTIMATE

Estimated direct costs for the dry FGD system include the SDA, fabric filter, major support facilities and BOP costs. The SO_2 control system cost is representative of a typical furnish and erect contract by a lime SDA/FF system supplier. The SDA/FF system costs estimated by CUECost are broken down into the major subsystems of reagent preparation, spray dryer absorber, waste handling systems, flue gas handling systems (new ID fans and ductwork) and support systems. A fabric filter is included in the estimate for the capture of entrained absorption products. BOP costs are described below in more detail.

As previously discussed, the existing Unit 1 stack is in poor physical condition and is to short for reuse. It would be possible to reuse the existing Unit 2 stack to exhaust the flue gas from Unit 1. Other than modifying the ductwork, significant modifications would not be required to make the Unit 2 stack suitable for operation with a dry FGD flue gas. BOP costs include long lengths of ductwork to the Unit 2 stack inlet and electrical subcontract. The results of the capital cost estimate are given in Table 3.4-2.

TABLE 3.4-2 – Capital Cost Estimate for MRYS Unit 1 Dry FGD/FF System

DIRECT COSTS	Estimated Cost ($2,006)	General Facilities Markup (10%)	Total Direct Cost
SDA System			
Reagent Prep System	$9,347,000	$935,000	$10,282,000
SO_2 Absorption System	$9,883,000	$988,000	$10,871,000
Flue Gas Handling System	$8,120,000	$812,000	$8,932,000
Byproduct Handling System	$1,902,000	$190,000	$2,092,000
Support Equipment	$3,078,000	$308,000	$3,386,000
		Dry FGD Total Direct Cost =	**$35,563,000**
Fabric Filter			
Fabric Filter Housing	$7,996,000	$800,000	$8,796,000
Bags	$1,268,000	$127,000	$1,395,000
Ash Handling System	$2,460,000	$246,000	$2,706,000
Instruments & Controls	$254,000	$25,000	$279,000
Freight	$636,000	$64,000	$700,000
Installation	$9,131,000	$913,000	$10,044,000
		Fabric Filter Total Direct Cost =	**$23,920,000**
BOP Costs			
Electrical Subcontract	$8,055,000	NA	$8,055,000
Additional Ductwork	$2,007,000	NA	$2,007,000
		BOP Total Direct Cost =	**$10,063,000**
		Total Direct Cost =	**$69,545,000**
INDIRECT COSTS			
		Contingency (20% of DC)	$13,909,000
		A/E Engineering and Construction Management (10% of DC)	$6,955,000
		Prime Contractor's Fee (3% of DC)	$2,086,000
		Allowance For Funds During Construction (AFDC 3.8%)	$2,643,000
		Indirect Cost Subtotal	$25,593,000
		Total Plant Investment (TPI)	**$95,138,000**
		Pre-Production Costs	$3,016,000
		Inventory	$258,000
		Total Capital Requirement	**$98,412,000**

A new stack was not included in the capital cost estimate. It was assumed for the purpose of the estimate that the existing Unit 2 stack would be reused.

The total estimated capital cost estimate for a complete, stand-alone lime SDA FGD system with a fabric filter, utilizing lime as a reagent is $98,412,000, or $383/kW.

3.4.1.3 WET FGD O&M COST ESTIMATE

The annual operating and maintenance costs (O&M) costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). The operating labor cost was developed as part of the CUECost model and is based on unit size and an operating labor rate of $40 per hour. However, because BOP estimates were modified, administrative and support labor and maintenance where calculated as described below. Table 3.4-3 summarizes the O&M cost estimates for the wet FGD system.

The fixed costs include operating labor, administrative and support labor and the maintenance material and labor costs. The maintenance material and labor cost was estimated as approximately 3% of the wet FGD system direct capital cost in Table 3.4-1. Administrative and support labor cost was estimated as 12% of the maintenance material and labor cost plus 30% of the operating labor costs. Previous studies and guidelines for FGD O&M costs by EPRI and others are in line with these percentages.

TABLE 3.4-3 – O&M Cost Estimate for MRYS Unit 1 Wet Lime FGD System

Fixed Costs	
Operating Labor	$1,490,000
Admin and Support labor	$741,000
Maintenance Material and Labor	$2,449,000
Total Fixed O&M Costs =	$4,680,000
Variable Costs	
Lime Reagent	$3,620,000
Byproduct Disposal	$555,000
Water	$88,000
Auxiliary Power	$1,339,000
Total Variable O&M Costs =	$5,602,000
Total Annual O&M Costs	**$10,282,000**
Net Annual O&M Cost ($/MWh)	**$5.40**

Variable costs include reagent, makeup water, FGD byproduct disposal and auxiliary power costs. The estimated annual costs for these consumables are based on consumption rates modeled by the CUECost model and the unit cost information provided in Table 1.2-1 Economic Design Criteria. A cost of $6 per ton for pumping the FGD waste slurry to the disposal pond was included for waste disposal.

3.4.1.4 DRY FGD O&M COST ESTIMATE

The O&M cost estimate for the SDA/FF alternative was estimated using CUECost. Lime usage was set at 1.3 lbmol of lime (CaO) per lbmol of SO_2 removed. A ratio of 7.5 lb of recycled solids per pound of lime added and 30% solids slurry were set as design conditions. A total of 13” w.g. pressure drop across the combined SDA/FF system was also specified. The Fabric Filter was sized for a gas-to-cloth ratio of 3.5 ACFM/Ft^2. A three year bag life was assumed. The purposes of this study, it was assumed that the ESP would be completely de-energized and result in a cost savings as shown. The results of the SDA/FF O&M cost estimate are summarized in Table 3.4-4.

TABLE 3.4-4 – O&M Cost Estimate for MRYS Unit 1 SDA/FF System

Fixed Costs	
Operating Labor	$1,199,000
Admin and Support Labor	$467,000
Maintenance Material and Labor	$3,233,000
Total Fixed O&M Costs =	**$4,899,000**
Variable Costs	
Lime Reagent	$4,806,000
Byproduct Disposal	$1,213,000
Water	$88,000
ESP Power Savings	($125,000)
Auxiliary Power	$1,208,000
Total Variable O&M Costs =	**$7,190,000**
Total Annual O&M Costs	**$12,089,000**
Net Annual O&M Cost ($/MWh)	**$6.32**

3.4.1.5 LEVELIZED TOTAL ANNUAL COST

In order to effectively compare the cost of installing, operating and maintaining each of the SO_2 control systems, capital and O&M costs can be evaluated on a levelized basis.

A Net Present Value (NPV) was calculated for the each alternative utilizing the estimated costs in Tables 3.4-1 through 3.4-4 and the economic conditions given in Table 1.2-1. The NPV calculation was based on a two year construction period, followed by a 20 year service life ending December 31, 2031. Estimated capital costs were split evenly over a two year construction period for all alternatives.

A system startup date of December 31, 2011 was used based upon the requirements of the Consent Decree. O&M costs were included through the end of the calendar year 2031. No salvage value was assumed at the end of the service life for any of the alternatives. The NPV for all SO_2 control technology alternatives are presented in Table 3.4-5.

The Levelized Total Annual Cost (LTAC) for all alternatives was calculated based on the same economic conditions and a 20 year project life and are presented below in Table 3.4-6 along with the emissions reduction, resultant emissions rate and the Unit Control Cost. The Unit Control Cost is the LTAC divided by the annual tons of SO_2 emissions that would be controlled by implementation of the respective alternative.

Table 3.4-5 – NPV of SO_2 Control Alternatives for MRYS Unit 1

SO_2 Control Alternative	Control Efficiency	Net Present Value (NPV) ($2006)
Wet FGD	95%	**$222,742,000**
Dry FGD	90%	**$232,880,000**

Service Life:	Through 2031
Interest:	6%
Construction Period:	2 years
Startup Date:	Dec. 31, 2011
Inflation Rate:	3% For Construction and 2.5% for O&M

Table 3.4-6 – Levelized Total Annual Cost of SO_2 Control Alternatives for MRYS Unit 1

SO_2 Control Alternative	Control Efficiency[4]	Annual Emission Reduction (tpy)	Installed Capital Cost ($2006)[1]	Annual O&M Cost ($2006)	Levelized Total Annual Cost ($2006)[2]	Actual Unit Control Cost ($/ton)[3]
Wet FGD	95%	20,460	$111,776,000	$10,282,000	**$22,584,000**	$1,104
SDA/FF	90%	19,383	$98,412,000	$12,089,000	**$23,676,000**	$1,221

1. All Costs in 2006 dollars.
2. For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.24873.
3. Overall control cost is LTAC divided by actual annual emissions reduction of each alternative.
4. SO_2 removal is across the FGD system.

The annual tons of SO_2 reduction in this BART analysis are calculated as the difference between the pre-controlled emissions from the historic highest 24-month rolling average pre-control baseline (firing lignite fuel at the historic 24-month average heat input with the historic 24-month average sulfur and heat contents and the historic 24-month average unit operating time) and the controlled emissions assumed to be at the same input conditions and unit operating time.

The Levelized Total Annual Cost and Unit Control Cost are used to evaluate the technology alternatives on a cost effectiveness basis. As can be seen from a review of Tables 3.4-5 and 3.4-6, the wet lime FGD alternative is the highest capital cost alternative but the lowest levelized total annual cost and net present value. Because the accuracy of the estimate (± 30%) is greater than the variance of the estimated LTACs (± 4%) and the Unit Control Costs (± 10%) for all post combustion control alternatives, none of the alternatives were excluded from further analysis on a cost basis.

The next step in the cost effectiveness analysis for the BART alternatives is to review the incremental cost effectiveness between the remaining alternatives. Table 3.4-7 contains a repetition of the cost and control information from Table 3.4-6 and the incremental cost effectiveness for each control alternative.

TABLE 3.4-7 – Incremental Cost Effectiveness of Unit 1 SO_2 BART Control Alternatives

BART Alternative	Levelized Total Annual Cost(1)	Annual Emission Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
Wet FGD	$22,584,000	20,460	-$1,014
Dry FGD	$23,676,000	19,383	NA

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1. 24873.

In the BART Determination guidelines, EPA does not provide definition, or even discussion of reasonable, or unreasonable, Unit Control Costs. Similarly, EPA does not address reasonable or unreasonable ranges for the incremental cost effectiveness. The incremental cost effectiveness is a marginal cost effectiveness between two specific alternatives. The incremental cost effectiveness for wet FGD versus dry FGD in Table 3.4-7 is within the range of reasonable costs used in other regulatory analyses and thus does not indicate that wet FGD is prohibitively expensive relative to the dry FGD alternative.

The cost analysis portion of the BART determination for MRYS Unit 1 has shown that none of the Unit Control Costs for the remaining alternatives are exceedingly expensive on a Unit Control Cost basis. From an economic analysis viewpoint, wet FGD appears to be the most cost effective evaluated SO_2 control alternative for MRYS Unit 1. However, because the capital costs of all of these technologies are subject to market conditions at the time of purchase, such as; alloy pricing, major equipment lead times (i.e., slurry pumps, ID fans, etc.) the relative closeness of the estimated capital costs is a good indicator that the cost ranking of these alternatives might even be reversed at the time of actual purchase.

3.4.2 ENERGY IMPACTS

The energy impacts of each alternative, in terms of both estimated kW of energy usage and the percent of total generation, are given in Table 3.4-8. The primary energy impacts of the wet FGD alternative consists of the additional electrical load resulting from pumps, blowers, booster fans, reagent preparation and vacuum pumps for byproduct slurry dewatering. The largest energy users for the dry FGD are pumps, blowers, atomizers, reagent preparation, additional fabric filter and ID fans. Building HVAC and interior and exterior lighting loads are also included, but the major energy consumption is due to the primary systems described above.

TABLE 3.4-8 – Energy Requirements of MRYS Unit 1 BART SO_2 Control Alternatives

BART Alternative	Energy Demand (kW)	Percent of Nominal Generation
Wet FGD	5,140	2.2%
Dry FGD	4,113	1.8%

3.4.3 NON-AIR QUALITY ENVIRONMENTAL IMPACTS

Non-air quality environmental impacts of the installation and operation of the various BART alternatives include hazardous waste generation, solid and aqueous waste streams, and salable products that could result from the implementation of various BART alternatives.

Captured mercury in the solid waste stream from any post combustion alternative would be present as a trace contaminant in the solid waste, not affecting disposal options as long as the waste passes the Toxic Characteristic Leaching Procedure (TCLP), which FGD system wastes have historically.

A wet FGD system for MRYS Unit 1 is estimated to produce approximately 12 tons per hour of solid waste. The waste stream would consist of solids and inerts in a slurry at approximately 10-15% solids. Over the course of a year, the total solid waste quantity from the wet FGD is estimated to be approximately 105,000 tons of solids which would be landfilled in the current permitted solid waste disposal facility near the plant. A dry FGD system for MRYS Unit 1 is estimated to produce approximately 28 tons per hour of solid waste or approximately 245,000 tons per year. The dry FGD waste stream contains approximately 95% solids and the majority is carried through to downstream particulate control. The increase in solids is mainly attributed to mixing with the fly ash which most likely has insufficient quality for sale. Thus, the dry FGD solids would be landfilled in the current permitted disposal facility.

3.4.4 SO_2 VISIBILITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 1

The remaining step for the BART SO_2 analysis was to conduct a visibility improvement determination for Unit 1. The NDDH Modeling Protocol[12] SO_2 emission rate of 7,231.2 lb/hr was modeled to determine a pre-control baseline visibility impact for MRYS Unit 1. This protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. The baseline visibility impact was then compared with the results predicted from a modeled post-control SO_2 emission rate based upon a 90% control dry scrubbing technology alternative SO_2 emission rate and a 95% control wet scrubbing technology alternative SO_2 emission rate relative to the protocol Unit 1 pre-control SO_2 emission rate.

According to the BART non-visibility impact analysis, wet flue gas desulfurization (FGD) was considered the most effective technology and therefore was evaluated as BART for Unit 1. The lowest post-control SO_2 emission rate of 361.6 lb/hr was based upon application of wet FGD control technology for a reduction of approximately 95 percent from the protocol mass emission rate. The next lowest post-control SO_2 emission rate of 723.1 lb/hr was based upon application of dry FGD control technology for a reduction of approximately 90 percent from the protocol mass emission rate.

The results of the visibility impairment modeling at the protocol baseline SO_2 emission rate for MRYS Unit 1 showed that three of the four Class 1 areas had a 90th percentile visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The 90th percentile visibility modeling results for the post-control 90% and 95% SO_2 reduction emission rates showed reductions in visibility impairment impact for all four Class 1 areas. In addition, the modeled 90th percentile visibility impairment impacts for all Class 1 areas at the post-control SO_2 emission rates were below the 0.50 dV threshold level. The predicted visibility impairments from the

[12] Ibid NDDH Final BART Protocol; November 2005.

modeling are presented in Table 3.4-9. This value is the average visibility impairment impact reduction over the three modeled years (2000-2002) for each affected Class 1 area. The predictions of 24-hour 98th percentile deciView data are also provided in Appendix A.

Table 3.4-9 – SO_2 Visibility Impairment Impacts and Reductions, MRYS Unit 1

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)			Visibility Impairment Reduction (deciView)	
	Protocol Emissions	Post-Control Emissions[2]		Post-Control Emissions[2]	
		90% Control	95% Control	90% Control	95% Control
TRNP-South Unit	0.549	0.250	0.173	0.299	0.375
TRNP-North Unit	0.628	0.269	0.165	0.359	0.463
TRNP-Elkhorn Ranch	0.374	0.160	0.111	0.214	0.263
Lostwood NWR	0.750	0.322	0.248	0.428	0.502

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.5-1 and the modeling results are presented in Appendix A.

2 - SO_2 emissions reduction by 90% and 95% over protocol baseline case. This scenario assumes protocol emission rates for NO_X and PM.

The number of days predicted to have visibility impairment due to MRYS Unit 1 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model. The results for the predicted protocol and post-control 90% and 95% SO_2 reduction emission rates from MRYS Unit 1 are summarized in Table 3.4-10 and Table 3.4-11, respectively. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control SO_2 emission rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

Table 3.4-10 – Visibility Impairment Improvements – MRYS Unit 1 Dry FGD SO_2 Control Impacts (Days)

Class 1 Area	SO_2 Control Technique	Days[2] Exceeding 0.5 dV in 2000	Days[2] Exceeding 0.5 dV in 2001	Days[2] Exceeding 0.5 dV in 2002	Days[2] Exceeding 1.0 dV in 2000	Days[2] Exceeding 1.0 dV in 2001	Days[2] Exceeding 1.0 dV in 2002	Consecutive Days[2] Exceeding 0.5 dV 2000	Consecutive Days[2] Exceeding 0.5 dV 2001	Consecutive Days[2] Exceeding 0.5 dV 2002
TRNP South	Protocol	38	30	48	19	15	26	3	3	4
	Dry FGD	10	20	24	4	11	12	1	3	3
	Reduction	*28*	*10*	*24*	*15*	*4*	*14*	*2*	*0*	*1*
TRNP North	Protocol	34	44	46	14	21	29	2	4	4
	Dry FGD	13	31	25	7	13	12	1	4	4
	Reduction	*21*	*13*	*21*	*7*	*8*	*17*	*1*	*0*	*0*
TRNP Elkhorn	Protocol	25	24	35	12	16	20	2	3	4
	Dry FGD	9	20	18	4	8	9	2	3	2
	Reduction	*16*	*4*	*17*	*8*	*8*	*11*	*0*	*0*	*2*
Lostwood NWR	Protocol	51	58	42	26	30	24	3	5	5
	Dry FGD	17	36	17	3	19	4	2	3	3
	Reduction	*34*	*22*	*25*	*23*	*11*	*20*	*1*	*2*	*2*

1 - Predicted visibility impairment impacts (90th percentile) for 2000-2002 for protocol and post-control SO_2 emission levels that are a reduction of 90%.
2 - Number of days for predicted visibility impairment impacts provided in Appendix A.

Table 3.4-11 – Visibility Impairment Improvements – MRYS Unit 1 Wet FGD SO_2 Control Impacts (Days)

Class 1 Area	SO_2 Control Technique	Days[2] Exceeding 0.5 dV in 2000	Days[2] Exceeding 0.5 dV in 2001	Days[2] Exceeding 0.5 dV in 2002	Days[2] Exceeding 1.0 dV in 2000	Days[2] Exceeding 1.0 dV in 2001	Days[2] Exceeding 1.0 dV in 2002	Consecutive Days[2] Exceeding 0.5 dV 2000	Consecutive Days[2] Exceeding 0.5 dV 2001	Consecutive Days[2] Exceeding 0.5 dV 2002
TRNP South	Protocol	38	30	48	19	15	26	3	3	4
	Wet FGD	11	11	23	4	3	14	1	2	3
	Reduction	*27*	*19*	*25*	*15*	*12*	*12*	*2*	*1*	*1*
TRNP North	Protocol	34	44	46	14	21	29	2	4	4
	Wet FGD	13	15	22	8	3	12	1	2	3
	Reduction	*21*	*29*	*24*	*6*	*18*	*17*	*1*	*2*	*0*
TRNP Elkhorn	Protocol	25	24	35	12	16	20	2	3	4
	Wet FGD	7	8	17	4	1	9	1	2	2
	Reduction	*18*	*16*	*18*	*8*	*15*	*11*	*1*	*1*	*2*
Lostwood NWR	Protocol	51	58	42	26	30	24	3	5	5
	Wet FGD	17	24	15	3	10	5	2	0	3
	Reduction	*34*	*34*	*27*	*23*	*20*	*19*	*1*	*5*	*2*

1 - Predicted visibility impairment impacts (90th percentile) for 2000-2002 for protocol and post-control SO_2 emission levels that are a reduction of 95%.
2 - Number of days for predicted visibility impairment impacts provided in Appendix A.

3.5 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS – UNIT 2

Step four in the BART analysis procedure is the impact analysis. The BART Determination Guidelines (70 FR 39166) lists four factors to be considered in the impact analysis.

- The costs of compliance;
- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

Three of the four impacts required by the BART Guidelines are discussed in the following sections. The remaining useful life of the source was determined to be greater than the project life definition in the EPA's OAQPS Control Cost Manual (EPA/453/B-96-001) and thus had no impact on the BART determination for MRYS. In addition, as described in Section 1.4, the visibility impairment impact of each alternative was evaluated as part of the impact analysis.

As previously stated in Section 3.2.1, the Consent Decree requires MRYS to modify the existing wet FGD system on Unit 2 to achieve a removal efficiency of at least 90%. Modifications to the existing wet FGD were evaluated as the minimum level of control for BART. In addition, because some wet FGD systems are capable of achieving 95% removal efficiency, modifications required to achieve 95% control were also evaluated for the wet FGD process.

3.5.1 COST ESTIMATES

The two wet FGD scenarios at 90 and 95 percent control involve modifications to the existing FGD process. Because the two control scenarios involve modifications to existing technology, the CUECost was not used to estimate costs for the Unit 2 SO_2 control alternatives. Instead, costs for retrofitting and operating the two BART alternatives were estimated from various literature sources and Burns & McDonnell's in-house experience and resources. Information from such sources was adjusted for known local conditions. Modifications to the existing wet FGD system and support equipment were identified and costs were estimated for comparison of the two wet FGD alternatives.

A Net Present Value (NPV) and Levelized Total Annual Cost (LTAC) was calculated for the each alternative utilizing the costs presented in the following sections, the same methodology presented in Section 3.4.1.5 and the economic conditions given in Table 1.2-1.

3.5.1.1 WET FGD COST ESTIMATE FOR 90% REMOVAL

The Consent Decree requires MRYS to upgrade the existing Unit 2 FGD system to achieve and maintain 90% SO_2 removal on a 30-day rolling average including any flue gas routed though a bypass duct. This analysis assumes that to achieve 90% removal, the bypass will be eliminated and lime reagent usage will increase. If the flue gas bypass is eliminated, the flue gas exiting the wet FGD will be at a saturated condition. Because the existing stack is not designed for saturated conditions and modifications to the existing stack require an extended outage that is incompatible with MRYS operations, the recommended solution is to construct a new stack suitable for saturated flue gas. Due to the arrangement of existing equipment, the new stack would be located approximately 220 feet from the existing stack and new ductwork would be required. Scrubbing 100% of the flue gas will also increase the volume of flow through each absorber module, thus increasing the velocity inside the vessel. New high velocity mist eliminators should be installed to account for the higher velocity and prevent corrosion issues caused by mist carryover into the ductwork and stack. The cost estimate for a wet FGD system achieving 90% control is summarized in Table 3.5-1.

Table 3.5-1 – Cost Estimate for MRYS Unit 2 Wet FGD System at 90% Control

Retrofit Capital Costs	
New Stack	$ 16,850,000
New Ductwork	$ 1,565,000
New Mist Eliminators	$ 810,000
Total Capital Costs =	**$ 19,225,000**
Annual O&M Costs	
Lime Reagent	$ 2,816,000
Byproduct Disposal	$ 477,000
Water	$ 163,000
Auxiliary Power	$ 1,074,000
Total O&M Costs =	**$ 4,530,000**
Net Present Value (NPV)	**$ 71,752,000**
Levelized Total Annual Cost (LTAC)	**$ 7,333,000**

3.5.1.2 WET FGD COST ESTIMATE FOR 95% REMOVAL

To modify the existing wet FGD system to achieve and maintain 95% SO_2 removal on a 30-day rolling average will require the bypass to be eliminated and cause lime reagent usage to increase. The capital improvements and associated costs will include the same new stack, new ductwork and new mist eliminators that were required to achieve 90% control. To modify the existing process to achieve the additional 5% control requires a detailed engineering analysis and design review which is outside the scope of this evaluation. However, at a minimum, the absorber modules would require the addition of perforated trays to increase the removal efficiency. The addition of trays in the absorber will increase the pressure drop across the system and will require ID fan modifications. Thus, Table 3.5-2 includes additional capital costs associated with the addition of trays and modification to the existing ID fans.

Table 3.5-2 – Cost Estimate for MRYS Unit 2 Wet FGD System at 95% Control

Retrofit Capital Costs	
New Stack	$ 16,850,000
New Ductwork	$ 1,565,000
New Mist Eliminators	$ 810,000
Absorber Trays	$ 853,000
ID Fan Modifications	$ 4,911,000
Total Capital Costs =	**$ 24,989,000**
Annual O&M Costs	
Lime Reagent	$ 2,964,000
Byproduct Disposal	$ 502,000
Water	$ 172,000
Auxiliary Power	$ 1,355,000
Total O&M Costs =	**$ 4,993,000**
Net Present Value (NPV)	**$ 82,424,000**
Levelized Total Annual Cost (LTAC)	**$ 8,414,000**

The next step in the analysis for the BART alternatives is to review the unit control cost and incremental cost effectiveness of the remaining scenarios. Table 3.5-3 contains a repetition of the cost information from Tables 3.5-1 and 3.5-2.

Because Unit 2 has existing SO_2 control, the historic highest 24-month rolling average represents a controlled emission rate. Thus, the baseline annual tons of SO_2 for Unit 2 in this BART analysis are calculated as the pre-controlled emissions from firing lignite fuel containing 1% sulfur at a heat input of 5,158 mmBtu/hr with the unit operating at 85% capacity. The resulting uncontrolled emissions are 15,600 pounds per hour or 58,000 tons per year. The controlled emissions assumed application of the respective removal efficiency to the baseline emission rate with the same input conditions and unit operating time. The annual tons of SO_2 reduction for Unit 2 are calculated as the difference between the protocol emissions and the controlled emissions associated to the respective removal efficiency.

TABLE 3.5-3 – Incremental Cost Effectiveness of Unit 2 SO_2 BART Control Alternatives

BART Alternative	Levelized Total Annual Cost[1]	Annual Emission Reduction (tpy)	Actual Unit Control Cost ($/ton)[2]	Incremental Cost Effectiveness ($/ton)
95% Control Wet FGD	$8,414,000	22,700	$371	$373
90% Control Wet FGD	$7,333,000	19,800	$370	NA

1. For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1. 24873.
2. Overall control cost is LTAC divided by actual annual emissions reduction of each alternative.

The Levelized Total Annual Cost and Unit Control Cost are used to evaluate the technology alternatives on a cost effectiveness basis. Because this is a comparison of the same technology at different removal efficiencies, one would expect the LTAC to be greater with the higher removal efficiency option.

In the BART Determination guidelines, EPA does not provide a definition, or even discussion of reasonable, or unreasonable, Unit Control Costs. Similarly, EPA does not address reasonable or unreasonable ranges for the incremental cost effectiveness. The incremental cost effectiveness is a marginal cost effectiveness between two specific alternatives. The incremental cost effectiveness for 95% control versus 90% control in Table 3.5-3 is within the range of reasonable costs used in other regulatory analyses and thus does not indicate that wet FGD at 95% control is prohibitively expensive relative to the 90% control alternative.

The cost analysis portion of the BART determination for MRYS Unit 2 has shown that none of the Unit Control Costs for the remaining alternatives are exceedingly expensive on a Unit Control Cost basis.

3.5.2 ENERGY AND NON-AIR QUALITY IMPACTS

The primary energy impacts of the wet FGD process consist of the additional electrical load resulting from pumps, blowers, booster fans, reagent preparation and vacuum pumps for byproduct slurry dewatering. Because the 90% control alternative evaluated for Unit 2 only includes modifications to existing equipment, the energy impacts are due to operational differences created by the modifications and are difficult to quantify. Thus, the energy impacts are estimated in terms of total system energy usage in kW and are included as part of the cost evaluation. An increase in energy usage for the 95% control alternative is a result of installing perforated trays and increasing the pressure drop of the absorber modules. The increase in pressure drop requires approximately 733 kW of additional ID fan power. A new category of non-air quality impact is not caused by the modifications to the existing system. The non-air quality impacts include increases to existing waste generation, are considered in the cost analysis portion of the analysis and no additional evaluation was performed.

3.5.3 SO_2 VISIBILITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 2

The remaining step for the BART SO_2 analysis was to conduct a visibility improvement determination for Unit 2. The NDDH BART protocol[13] SO_2 emission rate of 6,879.0 lb/hr was modeled to determine a pre-control baseline visibility impact for MRYS Unit 2. The protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. The baseline visibility impact was then compared with the results predicted from a modeled post-control SO_2 emission rate based upon 90% and 95% control wet scrubbing technology alternatives that utilize the modified, existing wet FGD system.

According to the BART non-visibility impact analysis, modifications to the existing wet FGD achieving 95% removal efficiency was the most effective technology and therefore was evaluated as BART for Unit 1. The 95% removal efficiency equates to an emission rate of 773.7 lb/hr SO_2. The next lowest post-control SO_2 emission rate of 1,574.4 lb/hr was based upon an upgrade of the existing wet FGD process to achieve 90% SO_2 reduction. The post-control CALPUFF model scenario for MRYS Unit 2 was conducted with the protocol NO_X and PM emission rates and the post-control SO_2 emission rate as discussed in Section 1.5.5 and Table 1.5-1.

[13] Ibid, NDDH Modeling Protocol.

The results of the visibility impairment modeling at the protocol baseline SO_2 emission rate for MRYS Unit 2 showed that three of the four Class 1 areas had a 90th percentile visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The 90th percentile visibility modeling results for the post-control 90% and 95% SO_2 reduction emission rates showed reductions in visibility impairment impact for all four Class 1 areas. In addition, the modeled 90th percentile visibility impairment impacts for all Class 1 areas at the post-control SO_2 emission rates were below the 0.50 dV threshold level. The predicted visibility impairments from the modeling are presented in Table 3.5-4. This value is the average visibility impairment impact reduction over the three modeled years (2000-2002) for each affected Class 1 area.

Table 3.5-4 – SO_2 Visibility Impairment Impacts and Reductions, MRYS Unit 2

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)			Visibility Impairment Reduction (deciView)	
	Protocol Emissions	Post-Control Emissions[2] 90% and 95% Control		Post-Control Emissions[2] 90% and 95% Control	
TRNP-South Unit	0.580	0.390	0.304	0.190	0.276
TRNP-North Unit	0.619	0.370	0.271	0.249	0.348
TRNP-Elkhorn Ranch	0.360	0.225	0.171	0.135	0.189
Lostwood NWR	0.775	0.493	0.405	0.282	0.370

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.5-1 and the modeling results are presented in Appendix A.
2 - SO_2 emissions reduction by 90% and 95% over protocol baseline case. This scenario assumes protocol emission rates for NO_X and PM.

The number of days predicted to have visibility impairment due to MRYS Unit 2 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model. The results are summarized and presented in Table 3.5-5 and 3.5-6. The visibility impairment impact and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control 90% and 95% SO_2 reduction emission rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

Table 3.5-5 – Visibility Impairment Improvements – MRYS Unit 2 90% Wet FGD SO_2 Control Impacts (Days)

Class 1 Area	SO_2 Control Technique	Days[2] Exceeding 0.5 dV in 2000	Days[2] Exceeding 0.5 dV in 2001	Days[2] Exceeding 0.5 dV in 2002	Days[2] Exceeding 1.0 dV in 2000	Days[2] Exceeding 1.0 dV in 2001	Days[2] Exceeding 1.0 dV in 2002	Consecutive Days[2] Exceeding 0.5 dV 2000	Consecutive Days[2] Exceeding 0.5 dV 2001	Consecutive Days[2] Exceeding 0.5 dV 2002
TRNP South	Protocol	41	28	51	18	14	27	3	3	4
	Wet FGD Upgraded to 90% Control	24	20	36	8	11	23	2	3	3
	Reduction	*17*	*8*	*15*	*10*	*3*	*4*	*1*	*0*	*1*
TRNP North	Protocol	32	43	47	18	21	29	2	4	4
	Wet FGD Upgraded to 90% Control	22	32	35	11	13	25	2	4	4
	Reduction	*10*	*11*	*12*	*7*	*8*	*4*	*0*	*0*	*0*
TRNP Elkhorn	Protocol	31	23	36	11	14	20	2	3	4
	Wet FGD Upgraded to 90% Control	12	21	24	8	10	16	2	3	2
	Reduction	*19*	*2*	*12*	*3*	*4*	*4*	*0*	*0*	*2*
Lostwood NWR	Protocol	52	51	48	30	31	25	3	3	5
	Wet FGD Upgraded to 90% Control	36	39	30	14	22	16	3	3	5
	Reduction	*16*	*12*	*18*	*16*	*9*	*9*	*0*	*0*	*0*

1 - Predicted visibility impairment impacts (90th percentile) for 2000-2002 for protocol and post-control SO_2 emission levels.
2 - Number of days for predicted visibility impairment impacts provided in Appendix A.

Table 3.5-6 – Visibility Impairment Improvements – MRYS Unit 2 95% Wet FGD SO_2 Control Impacts (Days)

Class 1 Area	SO_2 Control Technique	Days[2] Exceeding 0.5 dV in 2000	Days[2] Exceeding 0.5 dV in 2001	Days[2] Exceeding 0.5 dV in 2002	Days[2] Exceeding 1.0 dV in 2000	Days[2] Exceeding 1.0 dV in 2001	Days[2] Exceeding 1.0 dV in 2002	Consecutive Days[2] Exceeding 0.5 dV 2000	Consecutive Days[2] Exceeding 0.5 dV 2001	Consecutive Days[2] Exceeding 0.5 dV 2002
TRNP South	Protocol	41	28	51	18	14	27	3	3	4
	Wet FGD Upgraded to 95% Control	21	14	33	8	8	22	2	2	3
	Reduction	*20*	*14*	*18*	*10*	*6*	*5*	*1*	*1*	*1*
TRNP North	Protocol	32	43	47	18	21	29	2	4	4
	Wet FGD Upgraded to 95% Control	21	21	32	11	11	22	2	2	4
	Reduction	*11*	*22*	*15*	*7*	*10*	*7*	*0*	*2*	*0*
TRNP Elkhorn	Protocol	31	23	36	11	14	20	2	3	4
	Wet FGD Upgraded to 95% Control	12	13	21	6	5	16	2	2	2
	Reduction	*19*	*10*	*15*	*5*	*9*	*4*	*0*	*1*	*2*
Lostwood NWR	Protocol	52	51	48	30	31	25	3	3	5
	Wet FGD Upgraded to 95% Control	31	34	27	12	17	15	3	3	3
	Reduction	*21*	*17*	*21*	*18*	*14*	*10*	*0*	*0*	*2*

1 - Predicted visibility impairment impacts (90^{th} percentile) for 2000-2002 for protocol and post-control SO_2 emission levels.
2 - Number of days for predicted visibility impairment impacts provided in Appendix A.

4.0 PARTICULATE MATTER BART EVALUATION

Steps 1 through 5 of the BART analyses for PM emissions from MRYS Unit 1 and Unit 2 are described in this section. Potentially applicable SO_2 control technologies are first identified. A brief description of potential control options and their capabilities, including MRYS Unit 1 and Unit 2 existing PM air pollution control equipment, is provided. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to nominal PM control capability. The impacts analysis then reviews the estimated capital and O&M costs for each alternative, including taking a look at Balance Of Plant (BOP) requirements. Following the cost determination, the energy impacts and non-air quality impacts are reviewed for each technology. The impact based on the remaining useful life of the source is reviewed as part of the cost analysis. In the final step of the analysis, feasible and available technologies are assessed for their potential visibility impairment impact reduction capability via visibility modeling results. The results of the impact analyses are tabulated and potential BART control options are listed.

4.1 IDENTIFICATION OF RETROFIT PM CONTROL TECHNOLOGIES

The initial step in the BART determination is the identification of retrofit PM control technologies. In order to identify the applicable PM control technologies, several reference works were consulted, including the RACT/BACT/LAER Clearinghouse (RLBC). A preliminary list of control technologies and their estimated capabilities for potential application to MRYS was developed. As discussed in the introduction, Minnkota has entered into a Consent Decree (CD). The CD requires MRYS to maintain or upgrade the existing PM controls on both units to achieve specified emission rates. Because the CD specified the PM emission rate, the control technologies included in the BART analysis either meet the minimum emission rate specified by the CD or have more stringent emission rate. Table 4.1-1 contains the results of this effort.

TABLE 4.1-1 – PM Control Technologies Identified for BART Analysis

Control Technology	Approximate Control Efficiency
Fabric Filter or Baghouse	99.7%
COHPAC Baghouse	99.7%
New Electrostatic Precipitator	99.7%
Existing Electrostatic Precipitator	99.0%

4.2 TECHNICAL DESCRIPTION AND FEASIBLITY ANALYSIS

The second step in the BART analysis procedure is a technical feasibility analysis of the options identified in Step 1. The BART guidelines discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the “availability” and “applicability” of each control technology. A control technology is considered available, “if it has reached the stage of licensing and commercial availability.” (70 FR 39165) On the contrary, a control technology is not considered available, “if it is in the pilot scale testing stages of development.” (70 FR 39165) When considering a source’s applicability, technical judgment must be exercised to determine “if it can reasonably be installed and operated on the source type.” (70 FR 39165) All PM control technologies identified for this analysis are proven technologies that are technically feasible for review as a potential BART alternative for either Unit 1 or 2. The identified BART alternatives following the feasibility analysis are summarized in Table 4.2-1.

TABLE 4.2-1 – MRYS BART PM Control Feasibility Analysis Results

Control Technology	In full-scale service on Existing Utility Boilers	In Service on Other Combustion Sources	Commercially Available	Technically Applicable To Milton R. Young Station
Fabric Filter or Baghouse	Yes	Yes	Yes	Yes
COHPAC Baghouse	Yes	Yes	Yes	Yes
New Electrostatic Precipitator	Yes	Yes	Yes	Yes
Existing Electrostatic Precipitator	Yes	Yes	Yes	Yes

4.3 EVALUATE TECHNICALLY FEASIBILE PM CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis procedure is to evaluate the control effectiveness of the technically feasible alternatives. The PM control efficiency was reviewed and presented as part of the technology identification in Step 1 of the analysis. The alternatives are summarized in Table 4.3-1 and are ranked in descending order according to their effectiveness in PM control.

TABLE 4.3-1 – Feasible PM Control Technologies Identified for BART Analysis

Control Technology	Unit 1	Unit 2
Fabric Filter or Baghouse	0.015	0.015
COHPAC Baghouse	0.015	0.015
New Electrostatic Precipitator	0.015	0.015
Existing Electrostatic Precipitator	0.030	0.030

4.4 EVALUATION OF IMPACTS FOR FEASIBLE PM CONTROLS – UNIT 1

Step four in the BART analysis procedure is the impact analysis. The BART Determination Guidelines (70 FR 39166) lists four factors to be considered in the impact analysis.

- The costs of compliance;
- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

Three of the four impacts required by the BART Guidelines are discussed in the following sections. The remaining useful life of the source was determined to be greater than the project life definition in the EPA's OAQPS Control Cost Manual (EPA/453/B-96-001) and thus had no impact on the BART determination for MRYS. In addition, as described in Section 1.4, the visibility impairment impact of each alternative was evaluated as part of the impact analysis.

4.4.1 COST ESTIMATES

Cost estimates for the PM control technologies were completed utilizing the Coal Utility Environmental Cost (CUECost) computer model (Version 1.0) available from the U.S. Environmental Protection Agency and engineering estimates based upon Burns & McDonnell's in-house experience. The CUECost model is a spreadsheet-based computer model that was specifically developed to estimate the cost of air pollution control technologies for utility power plants within +/- 30 percent accuracy. The EPA released the version of the model used for this study in February 2000. The model is available for download from the U.S. EPA website at www.epa.gov/ttn/catc/products. Operating information utilized as input into the model for the purpose of cost estimating is presented in Appendix C. Economic information utilized as input into the model is given in Table 1.2-1. The cost estimates for a PM control alternatives are summarized in Table 4.4-1. A Net Present Value (NPV) and Levelized Total Annual Cost (LTAC) were calculated for the each alternative utilizing the costs summarized in Table 4.4-1.

TABLE 4.4-1 – Cost Estimates for Unit 1 PM Control Alternatives

	FF	COHPAC[1]	NEW ESP	EXISTING ESP[2]
Capital Costs				
Direct Costs	$21,133,000	$13,684,000	$23,112,000	$0
Indirect Costs	$8,453,000	$5,474,000	$9,245,000	$0
Total Capital Costs	**$29,856,000**	**$19,158,000**	**$32,357,000**	**$0**
O&M Costs				
Includes Maintenance Costs, Power Costs, and Replacement Costs (if any)				
Total O&M Costs	**$2,166,000**	**$1,571,000**	**$1,459,000**	**$1,459,000**
Net Present Value (NPV)	**$52,232,000**	**$35,862,000**	**$46,106,000**	**$17,667,000**
Levelized Total Annual Cost (LTAC)	**$5,284,000**	**$3,632,000**	**$4,643,000**	**$1,822,000**

1. COHPAC costs are scaled down to represent a similar fabric filter with a flue gas to cloth ratio of 6 ACFM/ft^2.
2. Costs associated with the operation of the existing ESP are assumed equal to the operating costs for a new ESP.

The next step in the analysis for the BART alternatives is to review the unit control cost and incremental cost effectiveness of the remaining scenarios. Table 4.4-2 contains a repetition of the cost information from Table 4.4-1.

Because Unit 1 has existing PM control, the historic highest 24-month rolling average represents a controlled emission rate. Thus, the baseline annual tons of PM for Unit 1 in this BART analysis are calculated as the pre-controlled emissions from firing lignite fuel with an ash content of 9.6% at a heat input of 2,955 mmBtu/hr with the unit operating at 85% capacity. Using the conservative approach that 50% of the ash is emitted as fly ash and 50% of the ash becomes bottom ash; the resulting uncontrolled emissions are approximately 32,100 tons per year. The controlled emissions assumed application of the respective removal efficiency to the baseline emission rate with the same input conditions and unit operating time. The annual tons of PM reduction for Unit 1 are calculated as the difference between the protocol emissions and the controlled emissions associated to the respective removal efficiency.

TABLE 4.4-2 – Incremental Cost Effectiveness of Unit 1 PM BART Control Alternatives

BART Alternative	Levelized Total Annual Cost[1]	Annual Emission Reduction (tpy)	Actual Unit Control Cost ($/ton)[2]	Incremental Cost Effectiveness ($/ton)
Fabric Filter or Baghouse	$5,284,000	61	$86,600	$56,800
New Electrostatic Precipitator	$4,643,000	61	$76,100	$46,200
COHPAC Baghouse	$3,632,000	61	$59,500	$29,700
Existing Electrostatic Precipitator	$1,822,000	Baseline	Baseline	Baseline

1. For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1. 24873.
2. Overall control cost is LTAC divided by actual annual emissions reduction of each alternative.

The Levelized Total Annual Cost and Unit Control Cost are used to evaluate the technology alternatives on a cost effectiveness basis. As can be seen from a review of Table 4.4-1 and 4.4-2, the fabric filter alternative is in the middle range for capital cost but has the highest levelized total annual cost and net present value.

In the BART Determination guidelines, EPA does not provide definition, or even discussion of reasonable, or unreasonable, Unit Control Costs. Similarly, EPA does not address reasonable or unreasonable ranges for the incremental cost effectiveness. The incremental cost effectiveness is a marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits between successively less effective alternatives. Because all the alternatives requiring new equipment for Unit 1 have the same removal rate, the incremental cost effectiveness is not effective for ranking the different technologies. However, the incremental cost is calculated for comparison between the existing ESP alternative and the other control options. The incremental cost effectiveness for each new control alternatives in Table 4.4-2 is above the range of reasonable costs used in other regulatory analyses and indicates that each new technology is prohibitively expensive. However, due to the lack of guidance on reasonable costs, the visibility analysis is conducted to determine if the additional controls are necessary to reduce visibility impacts.

4.4.2 PM VISIBLITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 1

The remaining step for the Unit 1 BART PM analysis was to conduct a visibility improvement determination. The modeling for Unit 1 uses two PM emission rates that distinguish between coarse and fine particulate as a basis for the visibility impairment impacts. One baseline emission rate representing the NDDH Modeling Protocol values of 36.7 lb PM_{Coarse}/hr and 5.5 lb PM_{Fine}/hr was modeled. The protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. However, as discussed in Section 1.5.5, the protocol emission rates are based upon actual maximum historical 24-hour emissions that are not representative of future maximum 24-hour emissions. After obtaining approval from NDDH to use alternative emission rates based upon representative stack conditions, Minnkota based the post-control emission rates upon application of CD specified rates applied to a more representative maximum heat input of 2,955 mmBtu/hr.

The Consent Decree requires MRYS to maintain or upgrade the PM controls on Unit 1 to achieve an emission rate of 0.015 lb PM/mmBtu if a dry FGD process is selected for SO_2 control or 0.030 lb PM/mmBtu if a wet FGD process is selected. A detailed engineering evaluation is required to determine if the existing ESP can achieve an emission rate of 0.015 lb PM/mmBtu for an extended period of time and that evaluation is outside the scope of this analysis. For the purposes of this report, it is assumed that the existing equipment will be able to meet the 0.030 lb PM/mmBtu emission rate specified by the CD. Post-control rates of 38.5 lb PM_{Coarse}/hr and 5.8 lb PM_{Fine}/hr were calculated and modeled based upon the CD emission rate of 0.015 lb PM/mmBtu and post-control rates of 77.1 lb PM_{Coarse}/hr and 11.6 lb PM_{Fine}/hr were calculated and modeled based upon the CD emission rate of 0.030 lb PM/mmBtu.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from protocol baseline and post-control hourly emission rates representing the visibility impairment impact reduction for MRYS Unit 1. The post-control CALPUFF model scenarios for MRYS Unit 1 were conducted with the protocol NO_X and SO_2 emission rates and the post-control PM emission rates as discussed previously in this section and in Table 1.5-1.

The results of the visibility impairment modeling at the protocol baseline PM emission rate for MRYS Unit 1 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for both post-control PM emission rates showed a reduction in visibility impairment impact for all Class 1 areas. In addition, the modeled visibility impairment impact for two of the Class 1 areas at both post-control PM emission rates was below the 0.50 dV threshold level. The TRNP – North and Lostwood Class 1 areas had a modeled visibility impairment impact above the 0.50 dV threshold level. The modeling results are presented in Table 4.4-3.

Table 4.4-3 – PM Visibility Impairment Impacts and Reductions, MRYS Unit 1

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)			Visibility Impairment Reduction (deciView)	
	Protocol Emissions	Post-Control Emissions[2] 0.030 and 0.015 Emission Rates		Post-Control Emissions[2] 0.030 and 0.015 Emission Rates	
TRNP-South Unit	0.549	0.466	0.465	0.083	0.084
TRNP-North Unit	0.628	0.503	0.500	0.125	0.128
TRNP-Elkhorn Ranch	0.374	0.328	0.328	0.046	0.046
Lostwood NWR	0.750	0.591	0.587	0.159	0.163

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.5-1 and the modeling results are presented in Appendix A.
2 - PM emissions corresponding to the 0.030 and 0.015 lb/mmBtu rates specified in the CD. This scenario assumes protocol emission rates for NO_X and SO_2.

The number of days predicted to have visibility impairment due to MRYS Unit 1 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol and post-control emission rates. The results are presented in Appendix A. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control PM emission rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

4.5 EVALUATION OF IMPACTS FOR FEASIBLE PM CONTROLS – UNIT 2

Step four in the BART analysis procedure is the impact analysis. The BART Determination Guidelines (70 FR 39166) lists four factors to be considered in the impact analysis.

- The costs of compliance;
- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

Three of the four impacts required by the BART Guidelines are discussed in the following sections. The remaining useful life of the source was determined to be greater than the project life definition in the EPA's OAQPS Control Cost Manual (EPA/453/B-96-001) and thus had no impact on the BART determination for MRYS. In addition, as described in Section 1.4, the visibility impairment impact of each alternative was evaluated as part of the impact analysis.

4.5.1 COST ESTIMATES

Cost estimates for the PM control technologies were completed utilizing the Coal Utility Environmental Cost (CUECost) computer model (Version 1.0) available from the U.S. Environmental Protection Agency and engineering estimates based upon Burns & McDonnell's in-house experience. The CUECost model is a spreadsheet-based computer model that was specifically developed to estimate the cost of air pollution control technologies for utility power plants within +/- 30 percent accuracy. The EPA released the version of the model used for this study in February 2000. The model is available for download from the U.S. EPA website at www.epa.gov/ttn/catc/products. Operating information utilized as input into the model for the purpose of cost estimating is presented in Appendix C. Economic information utilized as input into the model is given in Table 1.2-1. The cost estimates for a PM control alternatives are summarized in Table 4.5-1. A Net Present Value (NPV) and Levelized Total Annual Cost (LTAC) were calculated for the each alternative utilizing the costs summarized in Table 4.5-1.

TABLE 4.5-1 – Cost Estimates for Unit 2 PM Control Alternatives

	FF	COHPAC[1]	NEW ESP	EXISTING ESP[2]
Capital Costs				
Direct Costs	$31,774,000	$20,445,000	$37,251,000	$0
Indirect Costs	$12,710,000	$8,178,000	$14,900,000	$0
Total Capital Costs	**$44,484,000**	**$28,623,000**	**$52,151,000**	**$0**
O&M Costs				
Includes Maintenance Costs, Power Costs, and Replacement Costs (if any)				
Total O&M Costs	**$3,500,000**	**$2,552,000**	**$2,381,000**	**$2,381,000**
Net Present Value (NPV)	**$81,479,000**	**$56,059,000**	**$74,667,000**	**$28,832,000**
Levelized Total Annual Cost (LTAC)	**$8,249,000**	**$5,682,000**	**$7,520,000**	**$2,973,000**

1. COHPAC costs are scaled down to represent a similar fabric filter with a flue gas to cloth ratio of 6 ACFM/ft^2.
2. Costs associated with the operation of the existing ESP are assumed equal to the operating costs for a new ESP.

The next step in the analysis for the BART alternatives is to review the unit control cost and incremental cost effectiveness of the remaining scenarios. Table 4.5-2 contains a repetition of the cost information from Table 4.5-1.

Because Unit 2 has existing PM control, the historic highest 24-month rolling average represents a controlled emission rate. Thus, the baseline annual tons of PM for Unit 2 in this BART analysis are calculated as the pre-controlled emissions from firing lignite fuel with an ash content of 9.6% at a heat input of 5,158 mmBtu/hr with the unit operating at 85% capacity. Using the conservative approach that 50% of the ash is emitted as fly ash and 50% of the ash becomes bottom ash; the resulting uncontrolled emissions are approximately 56,100 tons per year. The controlled emissions assumed application of the respective removal efficiency to the baseline emission rate with the same input conditions and unit operating time. The annual tons of PM reduction for Unit 2 are calculated as the difference between the protocol emissions and the controlled emissions associated to the respective removal efficiency.

TABLE 4.5-2 – Incremental Cost Effectiveness of Unit 2 PM BART Control Alternatives

BART Alternative	Levelized Total Annual Cost[1]	Annual Emission Reduction (tpy)	Actual Unit Control Cost ($/ton)[2]	Incremental Cost Effectiveness ($/ton)
Fabric Filter or Baghouse	$8,249,000	602	$13,700	$8,700
New Electrostatic Precipitator	$7,520,000	602	$12,500	$7,600
COHPAC Baghouse	$5,682,000	602	$9,400	$4,500
Existing Electrostatic Precipitator	$2,973,000	Baseline	Baseline	Baseline

1. For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1. 24873.
2. Overall control cost is LTAC divided by actual annual emissions reduction of each alternative.

The Levelized Total Annual Cost and Unit Control Cost are used to evaluate the technology alternatives on a cost effectiveness basis. As can be seen from a review of Table 4.5-1 and 4.5-2, the fabric filter alternative is in the middle range for capital cost but has the highest levelized total annual cost and net present value.

In the BART Determination guidelines, EPA does not provide definition, or even discussion of reasonable, or unreasonable, Unit Control Costs. Similarly, EPA does not address reasonable or unreasonable ranges for the incremental cost effectiveness. The incremental cost effectiveness is a marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits between successively less effective alternatives. Because all the alternatives requiring new equipment for Unit 2 have the same removal rate, the incremental cost effectiveness is not effective for ranking the different technologies. However, the incremental cost is calculated for comparison between the existing ESP alternative and the other control options. The incremental cost effectiveness for each new control alternatives in Table 4.5-2 is above the range of reasonable costs used in other regulatory analyses and indicates that each new technology is prohibitively expensive. However, due to the lack of guidance on reasonable costs, the visibility analysis is conducted to determine if the additional controls are necessary to reduce visibility impacts.

4.5.2 PM VISIBLITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 2

The remaining step for the Unit 2 BART PM analysis was to conduct a visibility improvement determination. The modeling for Unit 2 uses two PM emission rates that distinguish between coarse and fine particulate as a basis for the visibility impairment impacts. One baseline emission rate representing the NDDH Modeling Protocol values of 178.7 lb PM_{Coarse}/hr and 28.1 lb PM_{Fine}/hr was modeled. The protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. However, as discussed in Section 1.5.5, the protocol emission rates are based upon actual maximum historical 24-hour emissions that are not representative of future maximum 24-hour emissions. After obtaining approval from NDDH to use alternative emission rates based upon representative stack conditions, Minnkota based the post-control emission rates upon application of CD specified rates applied to a more representative maximum heat input of 5,158 mmBtu/hr.

The Consent Decree requires MRYS to maintain or upgrade the PM controls on Unit 2 to achieve an emission rate of 0.030 lb PM/mmBtu. To achieve an emission rate greater than the 0.030 lb PM/mmBtu for an extended period of time may require the use of new control technology and would require a detailed engineering determination that is outside the scope of this analysis. For the purposes of this analysis, it is assumed that the existing equipment will be able to meet the 0.030 lb PM/mmBtu emission rate specified by the CD. Post-control rates of 133.7 lb PM_{Coarse}/hr and 21.0 lb PM_{Fine}/hr were calculated and modeled based upon the CD emission rate of 0.030 lb PM/mmBtu. No other PM emission rates were modeled based upon the results of the cost analysis.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from protocol baseline and post-control hourly emission rates representing the visibility impairment impact reduction for MRYS Unit 2. The post-control CALPUFF model scenario for MRYS Unit 2 was conducted with the protocol NO_X and SO_2 emission rates and the post-control PM emission rate as discussed previously in this section and in Table 1.5-1.

The results of the visibility impairment modeling at the protocol baseline PM emission rate for MRYS Unit 2 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for the post-control PM emission rate showed a reduction in visibility impairment impact for all Class 1 areas. The modeling results are presented in Table 4.5-3.

Table 4.5-3 – PM Visibility Impairment Impacts and Reductions, MRYS Unit 2

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction (deciView)
	Protocol Emissions	Post-Control Emissions[2]	
TRNP-South Unit	0.580	0.563	0.017
TRNP-North Unit	0.619	0.570	0.049
TRNP-Elkhorn Ranch	0.360	0.345	0.015
Lostwood NWR	0.775	0.739	0.036

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.5-1 and the modeling results are presented in Appendix A.
2 - PM emissions corresponding to the 0.030 lb/mmBtu specified in the CD. This scenario assumes protocol emission rates for NO_X and SO_2.

The number of days predicted to have visibility impairment due to MRYS Unit 2 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol emission rates. The results were summarized and presented in Table 4.5-4. Similarly, the same information for the post-control PM emission rates was summarized and is shown in Table 4.5-4. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control PM emission rates were reduced in the majority of cases. The TRNP – South Class 1 area in 2001 and 2002 each had one additional day with a visibility impairment impact exceeding 0.50 dV. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 areas, for Unit 2. The TRNP – South Class 1 area in 2001 and 2002 each had a impact increase of one day in terms of days exceeding 0.50 dV. The approximate visibility impact increase for 2001 was 4% and for 2002 was 2%. The impact reduction in terms of days exceeding 0.50 dV varies from approximately 0% in multiple areas and years to approximately 14% for TRNP – North in 2001. The impact reduction in terms of days exceeding 1.00 dV varies from approximately 0% in multiple areas and years to approximately 13% for Lostwood NWR in 2000.

There are several plausible explanations for an increase in the number of days with a visibility impairment impact exceeding 0.50 dV for TRNP – South in 2001 and 2002. One possible cause could be the reduced exit velocity that was due to an increase in stack diameter and an increased flow rate caused by scrubbing of all of the flue gas. Because the modeling results presented in Table 4.5-3 showed a reduction in visibility impairment impacts for all Class 1 areas, additional research was not conducted to determine the cause of the increase.

Table 4.5-4 – Visibility Impairment Improvements – MRYS Unit 2 PM Scenarios

Class 1 Area	PM Control Technique	Days[2] Exceeding 0.5 dV in 2000	Days[2] Exceeding 0.5 dV in 2001	Days[2] Exceeding 0.5 dV in 2002	Days[2] Exceeding 1.0 dV in 2000	Days[2] Exceeding 1.0 dV in 2001	Days[2] Exceeding 1.0 dV in 2002	Consecutive Days[2] Exceeding 0.5 dV 2000	Consecutive Days[2] Exceeding 0.5 dV 2001	Consecutive Days[2] Exceeding 0.5 dV 2002
TRNP South	Protocol	41	28	51	18	14	27	3	3	4
	Maintain ESP	37	29	52	16	13	27	3	3	4
TRNP North	Protocol	32	43	47	18	21	29	2	4	4
	Maintain ESP	29	37	45	18	21	29	2	4	4
TRNP Elkhorn	Protocol	31	23	36	11	14	20	2	3	4
	Maintain ESP	29	23	36	11	13	19	2	3	4
Lostwood NWR	Protocol	52	51	48	30	31	25	3	3	5
	Maintain ESP	50	48	45	27	27	25	3	3	4

1 - Predicted visibility impairment impacts (90th percentile) for 2000-2002 for protocol and post-control PM emission levels.
2 - Number of days for predicted visibility impairment impacts provided in Appendix A.

5.0 BART RECOMMENDATIONS

This report presents the analysis of control technologies for each of three major pollutants (nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM)) for Minnkota Power Cooperative Inc.'s (Minnkota's) Milton R. Young Station (MRYS) Units 1 and 2. The final result of this analysis is a recommendation of the Best Achievable Retrofit Technology (BART) for each unit based upon "the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology" (70 FR 39163). The presented emission rates in this section are the BART recommendation.

As stated previously in Section 1.3.2, this report uses the requirements of the Consent Decree (CD) and associated NO_X BACT analysis as part of the analysis. Although Unit 1 and Unit 2 at MRYS are BART-eligible, the CD also requires that the NDDH establish BACT for NO_X control. With the specification to establish BACT for NO_X, the BART analysis was modified to replace the first four BART evaluation steps with the NO_X BACT analysis. The first four steps of BART are usually used to identify technologies, determine feasibility and evaluate cost, energy, non-air quality and useful life impacts. Because a BACT analysis results in the selection of the best available control technology, the visibility impacts evaluation is the only remaining step in the determination that must be performed to satisfy BART for NO_X. The MRYS NO_X BACT analysis study reports and additional support documents were submitted to the NDDH on October 6, 2006, March 19, and April 23, 2007 respectively. In addition, because the CD also requires a minimum level of control for both SO_2 and PM, this analysis evaluates the visibility impairment impacts of the BACT-level control technologies specified for SO_2 and PM in the CD and control technologies that exceed the specified level of control. The BART analysis does not review technologies that do not achieve the minimum level of control specified in the CD.

5.1 UNIT 1 BART RECOMMENDATIONS

As stated in previous sections of the report, the steps of the technology evaluation provided in the BART Determination Guidelines were completed for Unit 1. Each pollutant required a different approach in order to determine BART. This section provides a brief description of the approach used for each pollutant and summarizes the results for Unit 1.

The Consent Decree required a NO_X BACT analysis. Because a BACT analysis results in the selection of the best available the control technology, the visibility impacts evaluation is the only remaining step in the determination that must be performed to satisfy BART for NO_X. According to the BACT analysis, Selective Non-Catalytic Reduction (SNCR) post-combustion technology used in conjunction with Advanced Separated Overfire Air (ASOFA) was considered the best available technology and therefore was evaluated as BART for Unit 1. The results of the visibility impact analysis for this combination of NO_X control technologies demonstrate a visibility impairment impacts reduction in all Class 1 areas to levels below the discernable 0.5 dV threshold levels. Based upon the BACT analysis and the visibility impact analysis, SNCR in conjunction with ASOFA is recommended as BART for NO_X emissions.

For SO_2 emissions, the CD requires MRYS to install either a dry FGD process at 90% control or a wet FGD process at 95% control. Thus, both of these technologies were evaluated. The Powerspan Electro-Catalytic Oxidation (ECO™) system would meet the CD requirements but was determined infeasible because it is not commercially proven in a full scale unit. The cost analysis for Unit 1 resulted in wet FGD technology being the most cost effective alternative due to its lower levelized total annual cost and higher control efficiency. The energy and non-air quality impacts for dry and wet FGD were similar in quantity and nature and considered negligible in differentiating between the two technologies. The visibility impairment impacts for both dry and wet FGD were reduced to levels below the discernable 0.5 dV threshold levels. Based upon the impact analyses, the technology recommended as BART for SO_2 emissions is the wet FGD process.

The Consent Decree requires MRYS to maintain or upgrade the PM controls on Unit 1 to achieve an emission rate of 0.015 lb PM/mmBtu if a dry FGD process is selected for SO_2 control or 0.030 lb PM/mmBtu if a wet FGD process is selected. Both emission rates were evaluated as part of this analysis. Based solely on the cost estimates for the Unit 1 PM control alternatives, the options requiring new equipment would be eliminated from the analysis due to their excessive expense. However, because the BART guidelines do not provide a specific value associated with eliminating individual control alternatives, visibility impacts were evaluated to verify the necessity of the more restrictive PM emission rate. The visibility impact analysis indicates that either evaluated emission rate reduces visibility impairment in the Class 1 areas. The maximum additional improvement in visibility impairment impact provided by the more stringent emission rate is less than 1% of the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. Thus, based upon the cost and visibility impact analyses, the technology recommended as BART for PM emissions is maintaining the existing ESP.

Table 5.1-1 summarizes the control technologies and associated emission rates that are recommended as BART for each pollutant. The recommended BART emission rates are presented as a 30-day rolling average to account for variations in boiler operation, fuel sulfur content and fly ash properties.

Table 5.1-1 – Recommended BART 30-Day Rolling Average, MRYS Unit 1

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Advanced Separated Over Fire Air (ASOFA) and Selective Non-Catalytic Reduction (SNCR)	0.36*
SO_2	Wet Flue Gas Desulfurization (FGD) Process	0.15
PM	Maintain Existing Electrostatic Precipitator (ESP)	0.030

* Excludes startups. See referenced BACT analysis for a detailed discussion.

The pollutant specific modeling results for MRYS Unit 1 described previously in the analysis represent the visibility impairment impact reduction attributable to a technology used to control an individual pollutant of concern. While this result supports an individual technology in terms of visibility impact reduction, the result is not representative of actual plant-wide operations. Application of the BART-recommended technologies will result in simultaneous control of all pollutants. Thus, a comparison of the visibility impairment reduction due to reducing the protocol emission rates to post-control emission rates for all pollutants on Unit 1 simultaneously is more representative of actual expected results. A modeling scenario was run to determine the visibility impairment impact reduction resulting from simultaneous application of all control technologies to Unit 1 and the results are presented in Table 5.1-2.

Table 5.1-2 – Visibility Impairment Impacts for Control of all Pollutants, MRYS Unit 1

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction
	Protocol Emissions	Post-Control Emissions	
TRNP-South Unit	0.549	0.077	0.472
TRNP-North Unit	0.628	0.075	0.553
TRNP-Elkhorn Ranch	0.374	0.050	0.324
Lostwood NWR	0.750	0.112	0.638

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.5-1 and the modeling results are presented in Appendix A.

The simultaneous control of all pollutants for MRYS Unit 1 results in visibility impairment impacts that are less than one fourth of the threshold the EPA designates as contributing to visibility impairment. These modeling results provide additional support for proposing the control technologies recommended in this report for NO_X, SO_2 and PM emissions as BART.

5.2 UNIT 2 BART RECOMMENDATIONS

As stated in previous sections of the report, the steps of the technology evaluation provided in the BART Determination Guidelines were completed for Unit 2. Each pollutant required a different approach in order to determine BART. This section provides a brief description of the approach used for each pollutant and summarizes the results for Unit 2.

As stated previously in the report, the Consent Decree required a NO_X BACT analysis. Because a BACT analysis results in the selection of the best available the control technology, the visibility impacts evaluation is the only remaining step in the determination that must be performed to satisfy BART for NO_X. According to the BACT analysis, Selective Non-Catalytic Reduction (SNCR) post-combustion technology used in conjunction with Advanced Separated Overfire Air (ASOFA) was considered the best available technology and therefore was evaluated as BART for Unit 2. The results of the visibility impact analysis for this combination of NO_X control technologies demonstrate a visibility impairment impacts reduction for three of the Class 1 areas to levels below the discernable 0.5 dV threshold levels. The Lostwood NWR Class 1 area had a modeled visibility impairment impact of 0.543 dV. Based upon the BACT analysis and the visibility impact analysis, SNCR in conjunction with ASOFA is recommended as BART for NO_X emissions.

For SO_2 emissions, the CD requires MRYS to modify the existing wet FGD system on Unit 2 to achieve a removal efficiency of at least 90%. Modifications to the existing wet FGD at 90% control were evaluated as the minimum level of control for BART. In addition, because some wet FGD systems are capable of achieving 95% removal efficiency, modifications required to achieve 95% control were also evaluated for the wet FGD process. The Powerspan Electro-Catalytic Oxidation (ECO™) system would meet the CD requirements but was determined infeasible because it is not commercially proven in a full scale unit. The cost analysis for Unit 2 resulted in 90% control wet FGD technology being the most cost effective alternative due to its lower levelized total annual cost. The energy and non-air quality impacts for both wet FGD control levels were similar in quantity and nature and considered negligible in differentiating between the two technologies. The visibility impairment impacts for 90% and 95% wet FGD processes were reduced to levels below the discernable 0.5 dV threshold levels.

Because this is an evaluation of the same technology at different control levels, the evaluated impacts are relatively similar. Thus, an additional parameter was evaluated to determine which control level should be recommended as BART. The levelized total annual cost (LTAC) and the average visibility impact reduction for the 4 areas were combined to obtain dollars per deciView of improvement. The difference between LTAC is $795,000. The average difference in visibility impact reduction is 0.082 dV. Thus, the cost for the additional impact reduction is approximately $9,700,000 per deciView of improvement. The cost to achieve relatively little visibility improvement is exceedingly high because either control level already improves visibility impact to below the discernable threshold levels. Based upon the impact analyses, the technology recommended as BART for SO_2 emissions is the wet FGD process at 90% removal efficiency.

The Consent Decree requires MRYS to maintain or upgrade the PM controls on Unit 2 to achieve an emission rate of 0.030 lb PM/mmBtu. Control technologies meeting this emission rate and a more stringent emission rate of 0.015 lb PM/mmBtu were evaluated as part of this analysis. Based solely on the cost estimates for the Unit 2 PM control alternatives, the options requiring new equipment would be eliminated from the analysis due to their excessive expense. However, because the BART guidelines do not provide a specific value associated with eliminating individual control alternatives, visibility impacts were evaluated to verify the necessity of more restrictive PM controls. The visibility impact analysis indicates that an emission rate of 0.030 lb PM/mmBtu reduces visibility impairment in the Class 1 areas. Thus, based upon the incremental cost and visibility impact analyses, the technology recommended as BART for PM emissions is maintaining the existing ESP.

Table 5.2-1 summarizes the control technologies and associated emission rates that are recommended as BART for each pollutant. The recommended BART emission rates are presented as a 30-day rolling average to account for variations in boiler operation, fuel sulfur content and fly ash properties.

Table 5.2-1 – Recommended BART 30-Day Rolling Average, MRYS Unit 2

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Advanced Separated Over Fire Air (ASOFA) and Selective Non-Catalytic Reduction (SNCR)	0.35*
SO_2	Upgrade of Existing Wet Flue Gas Desulfurization (FGD) Process	0.30
PM	Maintain Existing Electrostatic Precipitator (ESP)	0.030

* Excludes startups. See referenced BACT analysis for a detailed discussion.

The pollutant specific modeling results for MRYS Unit 2 described previously in this analysis represent the visibility impairment impact reduction attributable to a technology used to control an individual pollutant of concern. While this result supports an individual technology in terms of visibility impact reduction, the result is not representative of actual plant-wide operations. Application of the BART recommended technologies will result in simultaneous control of all pollutants. Thus, a comparison of the visibility impairment reduction due to reducing the protocol emission rates to post-control emission rates for all pollutants simultaneously is more representative of actual expected results. A modeling scenario was run to determine the visibility impairment impact reduction resulting from simultaneous application of all control technologies and the results are presented in Table 5.2-2.

Table 5.2-2 – Visibility Impairment Impacts for Control of all Pollutants, MRYS Unit 2

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction
	Protocol Emissions	Post-Control Emissions	
TRNP-South Unit	0.580	0.173	0.407
TRNP-North Unit	0.619	0.169	0.450
TRNP-Elkhorn Ranch	0.360	0.104	0.256
Lostwood NWR	0.775	0.243	0.532

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.5-1 and the modeling results are presented in Appendix A.

The simultaneous control of all pollutants for MRYS Unit 2 results in visibility impairment impacts that are less than one half of the threshold the EPA designates as contributing to visibility impairment.

These modeling results provide additional support for proposing the control technologies recommended as BACT for NO_X emissions and those recommended for SO_2 and PM emissions as BART.

In addition to the visibility impairment impact modeling scenario conducted to determine the effects of simultaneous control of all pollutants for the individual units, another modeling scenario was conducted to combine the effects of both units. The modeling showed that the visibility impairment impact for all Class 1 areas was reduced to below the threshold the EPA designates as contributing to visibility impairment. Results of this scenario (labeled Run 5) are provided in Appendix A.

Appendix A

Visibility Modeling Detailed Results

Emission Parameters for Minnkota Power Cooperative BART Modeling Analysis Milton R. Young Unit 1 & Unit 2												
Scenario/ Unit Number	Stack Height		Stack Diameter		Exit Velocity		Exit Temperature		Emission Rate (lbs/hr)			
	Feet	Meters	Feet	Meters	feet/sec	meters/sec	F	K	SO_2	NO_X	PM Fine	PM Coarse
Precontrol												
Unit 1	299.8	91.4	19.0	5.8	60.7	18.5	349.0	449.1	7231.2	2855.2	5.5	36.7
Unit 2	549.7	167.6	24.9	7.6	63.0	19.2	191.8	361.8	6879.0	5364.2	28.1	178.7
Run 1												
Unit 1	549.7	167.6	23.6	7.2	59.0	18.0	349.0	449.1	7231.2	1070.7	0.0	0.0
Unit 2	549.7	167.6	30.8	9.4	59.0	18.0	191.8	361.8	6879.0	2011.6	0.0	0.0
Unit1pm	549.7	167.6	23.6	7.2	59.0	18.0	349.0	449.1	0.0	0.0	5.5	36.7
Unit2pm	549.7	167.6	30.8	9.4	59.0	18.0	191.8	361.8	0.0	0.0	28.1	178.7
Run 2												
Unit 1 A	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	723.1	2855.2	0.0	0.0
Unit 1 B	549.7	167.6	21.6	6.6	55.0	16.8	144.3	335.4	361.6	2855.2	0.0	0.0
Unit 2 A	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	1574.4	5364.2	0.0	0.0
Unit 2 B	549.7	167.6	30.8	9.4	55.0	16.8	144.3	335.4	773.7	5364.2	0.0	0.0
Unit1pm	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	0.0	0.0	5.5	36.7
Unit2pm	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	0.0	0.0	28.1	178.7
Run 3												
Unit 1	549.7	167.6	23.6	7.2	59.0	18.0	349.0	449.1	7231.2	2855.2	0.0	0.0
Unit 2	549.7	167.6	30.8	9.4	59.0	18.0	191.8	361.8	6879.0	5364.2	0.0	0.0
Unit1pm A	549.7	167.6	23.6	7.2	59.0	18.0	349.0	449.1	0.0	0.0	5.8	38.5
Unit1pm B	549.7	167.6	21.8	6.6	68.7	20.9	349.0	449.1	0.0	0.0	11.55	77.08
Unit2pm	549.7	167.6	30.8	9.4	59.0	18.0	191.8	361.8	0.0	0.0	21.0	133.7
Run 4												
Unit 1	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	723.1	1070.7	0.0	0.0
Unit 2	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	1574.0	2011.6	0.0	0.0
Unit1pm	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	0.0	0.0	11.6	77.1
Unit2pm	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	0.0	0.0	21.0	133.7
Run 5												
Unit 1	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	723.1	1070.7	0.0	0.0
Unit 2	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	1574.0	2011.6	0.0	0.0
Unit1pm	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	0.0	0.0	11.6	77.1
Unit2pm	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	0.0	0.0	21.0	133.7

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 1
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	4.101	6.334	2.234	2000	74	51	105	2.8	85.77	14.19	0.02	0.02
98th %tile Delta-DV	1.151	3.257	2.106	2000	265	51	105	2.2	92.11	7.79	0.07	0.03
90th %tile Delta-DV	0.351	2.478	2.127	2000	100	51	105	2.3	81.38	18.42	0.14	0.06
2001												
Largest Delta-DV	3.062	5.168	2.106	2001	260	46	46	2.2	97.83	2.07	0.08	0.03
98th %tile Delta-DV	1.219	3.346	2.127	2001	92	52	106	2.3	68.95	30.87	0.13	0.05
90th %tile Delta-DV	0.302	2.429	2.127	2001	144	53	107	2.3	77.98	21.73	0.21	0.07
2002												
Largest Delta-DV	6.180	8.414	2.234	2002	78	53	107	2.8	85.05	14.89	0.03	0.02
98th %tile Delta-DV	2.766	5.021	2.255	2002	26	48	102	2.9	79.59	20.30	0.08	0.02
90th %tile Delta-DV	0.476	2.710	2.234	2002	91	53	107	2.8	82.61	17.36	0.01	0.02
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.457	4.690	2.234	2000	72	82	71	2.8	81.52	18.39	0.06	0.02
98th %tile Delta-DV	1.307	3.413	2.106	2000	217	82	71	2.2	92.58	7.32	0.07	0.03
90th %tile Delta-DV	0.306	2.475	2.170	2000	152	82	71	2.5	82.80	16.99	0.16	0.06
2001												
Largest Delta-DV	3.423	5.657	2.234	2001	64	82	71	2.8	88.52	11.43	0.04	0.01
98th %tile Delta-DV	1.833	3.939	2.106	2001	234	82	71	2.2	99.22	0.62	0.12	0.04
90th %tile Delta-DV	0.419	2.652	2.234	2001	85	82	71	2.8	67.30	32.52	0.12	0.05
2002												
Largest Delta-DV	4.941	7.174	2.234	2002	73	58	47	2.8	79.73	20.16	0.08	0.03
98th %tile Delta-DV	2.413	4.646	2.234	2002	51	84	113	2.8	84.00	15.92	0.05	0.02
90th %tile Delta-DV	0.506	2.634	2.127	2002	110	82	71	2.3	89.40	10.53	0.05	0.02
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	3.675	5.908	2.234	2000	74	90	72	2.8	86.93	13.03	0.02	0.02
98th %tile Delta-DV	0.823	2.929	2.106	2000	265	90	72	2.2	89.95	9.96	0.07	0.03
90th %tile Delta-DV	0.260	2.366	2.106	2000	261	90	72	2.2	94.09	5.63	0.20	0.08
2001												
Largest Delta-DV	2.417	4.650	2.234	2001	64	90	72	2.8	90.09	9.87	0.03	0.01
98th %tile Delta-DV	1.049	3.176	2.127	2001	92	90	72	2.3	69.93	29.89	0.13	0.05
90th %tile Delta-DV	0.209	2.336	2.127	2001	94	90	72	2.3	87.27	12.70	0.02	0.01
2002												
Largest Delta-DV	6.042	8.276	2.234	2002	73	90	72	2.8	80.78	19.11	0.08	0.03
98th %tile Delta-DV	2.465	4.699	2.234	2002	39	90	72	2.8	89.53	10.34	0.08	0.05
90th %tile Delta-DV	0.321	2.427	2.106	2002	255	90	72	2.2	95.00	4.58	0.28	0.14
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.150	6.425	2.275	2000	47	97	79	2.9	91.79	8.15	0.04	0.02
98th %tile Delta-DV	1.248	3.587	2.340	2000	336	97	79	3.2	87.73	12.20	0.04	0.03
90th %tile Delta-DV	0.537	2.682	2.145	2000	261	99	81	2.3	98.43	1.20	0.27	0.10
2001												
Largest Delta-DV	4.993	7.332	2.340	2001	326	99	81	3.2	87.88	12.05	0.05	0.02
98th %tile Delta-DV	2.003	4.278	2.275	2001	41	91	73	2.9	79.93	19.98	0.06	0.03
90th %tile Delta-DV	0.488	2.720	2.232	2001	208	99	81	2.7	93.60	6.33	0.05	0.02
2002												
Largest Delta-DV	3.121	5.396	2.275	2002	74	97	79	2.9	85.98	13.97	0.03	0.02
98th %tile Delta-DV	1.834	3.980	2.145	2002	111	99	81	2.3	84.27	15.60	0.10	0.03
90th %tile Delta-DV	0.436	2.581	2.145	2002	100	91	73	2.3	86.69	13.26	0.02	0.02

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 35
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 31
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 38
Number of days with Delta-Deciview > 1.00: 20
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 18
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 38
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 33
Number of days with Delta-Deciview > 1.00: 20
Max number of consecutive days with Delta-Deciview > 0.50: 4

Minnkota Power Cooperative
Milton R. Young Unit 2
BART Run 1
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	4.360	6.593	2.234	2000	74	51	105	2.8	75.04	24.79	0.08	0.09
98th %tile Delta-DV	1.273	3.548	2.276	2000	316	46	46	3	67.31	32.39	0.22	0.08
90th %tile Delta-DV	0.358	2.591	2.234	2000	46	6	6	2.8	34.02	64.43	1.20	0.35
2001												
Largest Delta-DV	3.019	5.125	2.106	2001	260	46	46	2.2	95.13	4.35	0.37	0.14
98th %tile Delta-DV	1.476	3.625	2.149	2001	205	51	105	2.4	86.70	11.94	1.07	0.30
90th %tile Delta-DV	0.332	2.438	2.106	2001	230	41	41	2.2	90.53	7.68	1.40	0.40
2002												
Largest Delta-DV	6.478	8.712	2.234	2002	78	53	107	2.8	75.48	24.27	0.14	0.11
98th %tile Delta-DV	3.008	5.262	2.255	2002	26	48	102	2.9	66.05	33.52	0.32	0.11
90th %tile Delta-DV	0.528	2.634	2.106	2002	241	48	102	2.2	94.68	5.14	0.12	0.06
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.588	4.821	2.234	2000	72	82	71	2.8	68.73	30.9	0.28	0.1
98th %tile Delta-DV	1.345	3.451	2.106	2000	217	82	71	2.2	85.57	13.95	0.33	0.15
90th %tile Delta-DV	0.317	2.445	2.127	2000	286	82	71	2.3	65.24	34.25	0.35	0.16
2001												
Largest Delta-DV	3.474	5.708	2.234	2001	64	82	71	2.8	79.09	20.68	0.16	0.07
98th %tile Delta-DV	1.793	3.899	2.106	2001	234	82	71	2.2	97.90	1.29	0.62	0.19
90th %tile Delta-DV	0.442	2.676	2.234	2001	55	82	71	2.8	65.06	34.64	0.21	0.09
2002												
Largest Delta-DV	5.446	7.679	2.234	2002	73	63	52	2.8	65.53	33.99	0.35	0.12
98th %tile Delta-DV	2.692	4.925	2.234	2002	51	82	71	2.8	71.04	28.62	0.24	0.11
90th %tile Delta-DV	0.554	2.682	2.127	2002	138	82	71	2.3	67.69	31.23	0.76	0.32
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	3.876	6.11	2.234	2000	74	90	72	2.8	76.78	23.06	0.07	0.09
98th %tile Delta-DV	0.922	3.156	2.234	2000	69	90	72	2.8	61.84	37.64	0.36	0.16
90th %tile Delta-DV	0.278	2.512	2.234	2000	32	90	72	2.8	60.45	39.14	0.23	0.18
2001												
Largest Delta-DV	2.419	4.653	2.234	2001	64	90	72	2.8	81.69	18.11	0.14	0.06
98th %tile Delta-DV	1.131	3.364	2.234	2001	84	90	72	2.8	64.16	35.36	0.34	0.15
90th %tile Delta-DV	0.215	2.342	2.127	2001	101	90	72	2.3	84.12	15.80	0.04	0.04
2002												
Largest Delta-DV	6.564	8.797	2.234	2002	73	90	72	2.8	67.55	32.01	0.33	0.11
98th %tile Delta-DV	2.513	4.768	2.255	2002	29	90	72	2.9	69.55	30.13	0.23	0.09
90th %tile Delta-DV	0.339	2.466	2.127	2002	125	90	72	2.3	62.64	37.12	0.05	0.19
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.043	6.319	2.275	2000	47	97	79	2.9	79.16	20.58	0.18	0.09
98th %tile Delta-DV	1.393	3.669	2.275	2000	48	99	81	2.9	73.88	25.93	0.12	0.07
90th %tile Delta-DV	0.585	2.881	2.297	2000	12	99	81	3	72.77	26.8	0.26	0.18
2001												
Largest Delta-DV	5.139	7.479	2.340	2001	327	99	81	3.2	71.41	28.32	0.18	0.09
98th %tile Delta-DV	2.042	4.188	2.145	2001	259	97	79	2.3	91.38	8.26	0.26	0.10
90th %tile Delta-DV	0.580	2.791	2.211	2001	179	99	81	2.6	69.45	29.47	0.82	0.26
2002												
Largest Delta-DV	3.287	5.562	2.275	2002	74	97	79	2.9	75.12	24.66	0.14	0.08
98th %tile Delta-DV	1.935	4.274	2.340	2002	312	99	81	3.2	71.84	27.82	0.17	0.17
90th %tile Delta-DV	0.466	2.611	2.145	2002	247	97	79	2.3	96.79	2.20	0.70	0.31

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 26
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 40
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 32
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 40
Number of days with Delta-Deciview > 1.00: 23
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 30
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 41
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 39
Number of days with Delta-Deciview > 1.00: 22
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 34
Number of days with Delta-Deciview > 1.00: 20
Max number of consecutive days with Delta-Deciview > 0.50: 4

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 2A
2000-2002

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	2.580	4.814	2.234	2000	72	53	107	2.8	11.93	87.88	0.14	0.05
98th %tile Delta-DV	0.583	2.817	2.234	2000	41	1	1	2.8	6.55	93.18	0.19	0.08
90th %tile Delta-DV	0.200	2.327	2.127	2000	287	46	46	2.3	23.65	76.13	0.15	0.07
2001												
Largest Delta-DV	3.062	5.168	2.106	2001	260	46	46	2.2	97.82	2.07	0.08	0.03
98th %tile Delta-DV	1.219	3.346	2.127	2001	92	52	106	2.3	68.94	30.87	0.14	0.05
90th %tile Delta-DV	0.302	2.429	2.127	2001	144	53	107	2.3	77.98	21.73	0.21	0.07
2002												
Largest Delta-DV	3.954	6.187	2.234	2002	78	45	45	2.8	14.93	84.96	0.06	0.04
98th %tile Delta-DV	1.768	4.023	2.255	2002	29	3	3	2.9	13.56	86.31	0.09	0.04
90th %tile Delta-DV	0.247	2.523	2.276	2002	330	47	101	3.0	15.64	84.29	0.03	0.04
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.396	4.630	2.234	2000	36	82	71	2.8	9.63	90.16	0.14	0.07
98th %tile Delta-DV	0.762	2.889	2.127	2000	98	84	113	2.3	10.23	89.46	0.24	0.07
90th %tile Delta-DV	0.144	2.419	2.276	2000	336	63	52	3.0	4.02	95.71	0.21	0.06
2001												
Largest Delta-DV	3.423	5.657	2.234	2001	64	82	71	2.8	88.52	11.43	0.04	0.01
98th %tile Delta-DV	1.833	3.939	2.106	2001	234	82	71	2.2	99.21	0.62	0.12	0.04
90th %tile Delta-DV	0.419	2.652	2.234	2001	85	82	71	2.8	67.30	32.52	0.12	0.05
2002												
Largest Delta-DV	3.890	6.123	2.234	2002	73	63	52	2.8	11.76	88.06	0.14	0.04
98th %tile Delta-DV	1.522	3.776	2.255	2002	29	85	114	2.9	12.95	86.92	0.10	0.04
90th %tile Delta-DV	0.244	2.414	2.170	2002	154	82	71	2.5	19.45	80.22	0.24	0.09
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	2.018	4.251	2.234	2000	74	90	72	2.8	19.61	80.31	0.04	0.04
98th %tile Delta-DV	0.528	2.677	2.149	2000	184	90	72	2.4	45.84	53.38	0.56	0.21
90th %tile Delta-DV	0.122	2.292	2.170	2000	164	90	72	2.5	62.36	36.69	0.68	0.27
2001												
Largest Delta-DV	2.417	4.650	2.234	2001	64	90	72	2.8	90.08	9.87	0.03	0.01
98th %tile Delta-DV	1.049	3.176	2.127	2001	92	90	72	2.3	69.93	29.88	0.13	0.05
90th %tile Delta-DV	0.209	2.336	2.127	2001	94	90	72	2.3	87.27	12.70	0.02	0.01
2002												
Largest Delta-DV	4.326	6.559	2.234	2002	73	90	72	2.8	13.02	86.81	0.12	0.04
98th %tile Delta-DV	1.589	3.843	2.255	2002	29	90	72	2.9	13.69	86.19	0.09	0.04
90th %tile Delta-DV	0.148	2.276	2.127	2002	116	90	72	2.3	5.46	94.29	0.18	0.07
LOSTWOOD NWA												
2000												
Largest Delta-DV	2.844	5.119	2.275	2000	47	97	79	2.9	17.17	82.73	0.07	0.03
98th %tile Delta-DV	0.870	3.037	2.167	2000	216	97	79	2.4	20.55	79.22	0.18	0.05
90th %tile Delta-DV	0.277	2.510	2.232	2000	196	91	73	2.7	51.06	47.79	0.82	0.33
2001												
Largest Delta-DV	4.993	7.333	2.340	2001	326	99	81	3.2	87.88	12.05	0.05	0.02
98th %tile Delta-DV	2.003	4.278	2.275	2001	41	91	73	2.9	79.94	19.98	0.05	0.03
90th %tile Delta-DV	0.488	2.720	2.232	2001	208	99	81	2.7	93.60	6.33	0.05	0.02
2002												
Largest Delta-DV	1.721	3.996	2.275	2002	74	97	79	2.9	18.00	81.90	0.06	0.03
98th %tile Delta-DV	0.899	3.239	2.340	2002	312	91	73	3.2	14.82	85.04	0.07	0.08
90th %tile Delta-DV	0.201	2.411	2.211	2002	172	99	81	2.6	37.25	61.19	1.18	0.38

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 31
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 18
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 3

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 2B
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	2.536	4.770	2.234	2000	72	54	108	2.8	6.26	93.55	0.15	0.05
98th %tile Delta-DV	0.594	2.870	2.276	2000	336	53	107	3.0	1.94	97.71	0.27	0.08
90th %tile Delta-DV	0.167	2.294	2.127	2000	287	46	46	2.3	13.51	86.24	0.17	0.08
2001												
Largest Delta-DV	1.268	3.396	2.127	2001	112	36	36	2.3	5.54	94.14	0.25	0.07
98th %tile Delta-DV	0.635	2.911	2.276	2001	338	28	28	3.0	6.70	92.87	0.30	0.13
90th %tile Delta-DV	0.095	2.328	2.234	2001	43	52	106	2.8	9.93	89.85	0.16	0.05
2002												
Largest Delta-DV	3.823	6.056	2.234	2002	78	45	45	2.8	8.02	91.87	0.07	0.05
98th %tile Delta-DV	1.694	3.927	2.234	2002	64	53	107	2.8	6.78	93.05	0.10	0.06
90th %tile Delta-DV	0.258	2.385	2.127	2002	117	6	6	2.3	1.96	97.65	0.22	0.17
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.746	4.980	2.234	2000	36	82	71	2.8	4.77	95.00	0.15	0.07
98th %tile Delta-DV	1.097	3.330	2.234	2000	54	82	71	2.8	9.69	90.05	0.20	0.07
90th %tile Delta-DV	0.157	2.327	2.170	2000	152	82	71	2.5	8.30	91.29	0.30	0.12
2001												
Largest Delta-DV	1.888	4.142	2.255	2001	12	83	112	2.9	11.43	88.31	0.20	0.07
98th %tile Delta-DV	0.837	2.964	2.127	2001	92	63	52	2.3	3.47	96.29	0.18	0.06
90th %tile Delta-DV	0.117	2.244	2.127	2001	275	82	71	2.3	11.28	88.16	0.34	0.21
2002												
Largest Delta-DV	3.855	6.088	2.234	2002	73	63	52	2.8	6.18	93.63	0.15	0.05
98th %tile Delta-DV	1.594	3.827	2.234	2002	66	83	112	2.8	3.85	95.82	0.24	0.09
90th %tile Delta-DV	0.222	2.328	2.106	2002	234	67	56	2.2	20.43	78.42	0.90	0.25
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.890	4.123	2.234	2000	74	90	72	2.8	10.82	89.09	0.04	0.05
98th %tile Delta-DV	0.482	2.716	2.234	2000	41	90	72	2.8	5.46	94.34	0.12	0.08
90th %tile Delta-DV	0.109	2.236	2.127	2000	299	90	72	2.3	11.75	88.14	0.07	0.04
2001												
Largest Delta-DV	1.095	3.222	2.127	2001	92	90	72	2.3	3.68	96.12	0.15	0.06
98th %tile Delta-DV	0.525	2.631	2.106	2001	261	90	72	2.2	23.67	75.91	0.28	0.13
90th %tile Delta-DV	0.068	2.344	2.276	2001	315	90	72	3.0	6.65	93.22	0.08	0.05
2002												
Largest Delta-DV	4.225	6.459	2.234	2002	73	90	72	2.8	6.90	92.92	0.13	0.04
98th %tile Delta-DV	1.533	3.808	2.276	2002	336	90	72	3.0	7.54	92.24	0.17	0.05
90th %tile Delta-DV	0.155	2.282	2.127	2002	116	90	72	2.3	2.76	96.99	0.18	0.07
LOSTWOOD NWA												
2000												
Largest Delta-DV	2.864	5.139	2.275	2000	47	97	79	2.9	9.39	90.49	0.08	0.04
98th %tile Delta-DV	0.820	2.987	2.167	2000	216	97	79	2.4	11.41	88.34	0.19	0.05
90th %tile Delta-DV	0.274	2.549	2.275	2000	45	91	73	2.9	7.82	92.11	0.04	0.03
2001												
Largest Delta-DV	4.434	6.774	2.340	2001	327	99	81	3.2	7.98	91.90	0.07	0.04
98th %tile Delta-DV	1.194	3.534	2.340	2001	333	99	81	3.2	7.17	92.60	0.14	0.09
90th %tile Delta-DV	0.280	2.447	2.167	2001	235	99	81	2.4	5.98	93.00	0.80	0.23
2002												
Largest Delta-DV	1.619	3.895	2.275	2002	74	97	79	2.9	9.86	90.04	0.07	0.04
98th %tile Delta-DV	0.839	3.115	2.275	2002	69	99	81	2.9	4.83	95.07	0.05	0.05
90th %tile Delta-DV	0.189	2.334	2.145	2002	100	91	73	2.3	10.37	89.52	0.06	0.05

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 11
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 11
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 15
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 15
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 3

Minnkota Power Cooperative
Milton R. Young Unit 2
BART Run 2A
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	4.153	6.387	2.234	2000	72	53	107	2.8	13.85	85.69	0.34	0.12
98th %tile Delta-DV	1.159	3.392	2.234	2000	69	56	110	2.8	11.29	88.21	0.36	0.13
90th %tile Delta-DV	0.340	2.467	2.127	2000	301	54	108	2.3	3.47	94.82	1.31	0.41
2001												
Largest Delta-DV	3.019	5.125	2.106	2001	260	46	46	2.2	95.13	4.35	0.37	0.14
98th %tile Delta-DV	1.476	3.625	2.149	2001	205	51	105	2.4	86.70	11.94	1.07	0.30
90th %tile Delta-DV	0.332	2.438	2.106	2001	230	41	41	2.2	90.53	7.68	1.40	0.40
2002												
Largest Delta-DV	6.473	8.706	2.234	2002	78	45	45	2.8	16.99	82.74	0.16	0.11
98th %tile Delta-DV	3.080	5.335	2.255	2002	29	3	3	2.9	15.06	84.61	0.23	0.10
90th %tile Delta-DV	0.497	2.624	2.127	2002	294	47	101	2.3	14.54	84.71	0.51	0.24
TRNP NORTH UNIT												
2000												
Largest Delta-DV	3.452	5.685	2.234	2000	36	82	71	2.8	11.65	87.78	0.38	0.18
98th %tile Delta-DV	1.332	3.566	2.234	2000	74	67	56	2.8	20.92	78.90	0.08	0.11
90th %tile Delta-DV	0.257	2.384	2.127	2000	119	82	71	2.3	15.13	83.25	1.23	0.38
2001												
Largest Delta-DV	3.474	5.708	2.234	2001	64	82	71	2.8	79.09	20.68	0.16	0.07
98th %tile Delta-DV	1.793	3.899	2.106	2001	234	82	71	2.2	97.90	1.29	0.62	0.19
90th %tile Delta-DV	0.442	2.676	2.234	2001	55	82	71	2.8	65.06	34.64	0.21	0.09
2002												
Largest Delta-DV	6.094	8.327	2.234	2002	73	63	52	2.8	13.44	86.13	0.32	0.11
98th %tile Delta-DV	2.666	4.900	2.234	2002	75	82	71	2.8	17.44	82.13	0.28	0.16
90th %tile Delta-DV	0.410	2.685	2.276	2002	352	71	60	3.0	13.41	86.31	0.18	0.10
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	3.513	5.747	2.234	2000	74	90	72	2.8	21.72	78.08	0.09	0.11
98th %tile Delta-DV	1.068	3.174	2.106	2000	247	90	72	2.2	68.84	28.73	1.68	0.74
90th %tile Delta-DV	0.201	2.307	2.106	2000	239	90	72	2.2	43.86	55.24	0.58	0.32
2001												
Largest Delta-DV	2.419	4.653	2.234	2001	64	90	72	2.8	81.69	18.11	0.14	0.06
98th %tile Delta-DV	1.131	3.364	2.234	2001	84	90	72	2.8	64.16	35.36	0.34	0.15
90th %tile Delta-DV	0.215	2.342	2.127	2001	101	90	72	2.3	84.12	15.80	0.04	0.04
2002												
Largest Delta-DV	6.981	9.214	2.234	2002	73	90	72	2.8	14.69	84.89	0.31	0.11
98th %tile Delta-DV	2.789	5.044	2.255	2002	29	90	72	2.9	15.14	84.54	0.23	0.09
90th %tile Delta-DV	0.259	2.387	2.127	2002	116	90	72	2.3	6.26	93.09	0.47	0.18
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.227	6.502	2.275	2000	47	97	79	2.9	19.67	80.05	0.19	0.09
98th %tile Delta-DV	1.443	3.718	2.275	2000	48	99	81	2.9	19.14	80.64	0.14	0.08
90th %tile Delta-DV	0.494	2.639	2.145	2000	114	91	73	2.3	29.95	68.59	0.87	0.59
2001												
Largest Delta-DV	5.139	7.479	2.340	2001	327	99	81	3.2	71.41	28.32	0.18	0.09
98th %tile Delta-DV	2.042	4.188	2.145	2001	259	97	79	2.3	91.38	8.26	0.26	0.10
90th %tile Delta-DV	0.580	2.791	2.211	2001	179	99	81	2.6	69.45	29.47	0.82	0.26
2002												
Largest Delta-DV	3.117	5.392	2.275	2002	74	97	79	2.9	19.78	79.98	0.16	0.09
98th %tile Delta-DV	1.486	3.654	2.167	2002	239	93	75	2.4	33.81	65.60	0.41	0.18
90th %tile Delta-DV	0.405	2.572	2.167	2002	234	97	79	2.4	38.85	60.11	0.64	0.40

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 23
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 32
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 35
Number of days with Delta-Deciview > 1.00: 25
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 39
Number of days with Delta-Deciview > 1.00: 22
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 30
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 5

Minnkota Power Cooperative
Milton R. Young Unit 2
BART Run 2B
2000-2002

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	3.913	6.147	2.234	2000	72	53	107	2.8	7.32	92.19	0.36	0.13
98th %tile Delta-DV	1.096	3.329	2.234	2000	69	56	110	2.8	5.89	93.58	0.39	0.14
90th %tile Delta-DV	0.317	2.445	2.127	2000	106	48	102	2.3	4.07	94.75	0.92	0.26
2001												
Largest Delta-DV	2.223	4.351	2.127	2001	92	52	106	2.3	3.96	95.53	0.37	0.15
98th %tile Delta-DV	1.095	3.370	2.276	2001	328	45	45	3.0	11.21	88.62	0.10	0.08
90th %tile Delta-DV	0.154	2.260	2.106	2001	266	51	105	2.2	4.72	93.42	1.47	0.39
2002												
Largest Delta-DV	6.099	8.332	2.234	2002	78	45	45	2.8	9.05	90.66	0.17	0.12
98th %tile Delta-DV	2.876	5.131	2.255	2002	29	4	4	2.9	7.99	91.65	0.25	0.10
90th %tile Delta-DV	0.442	2.569	2.127	2002	136	54	108	2.3	4.66	93.59	1.37	0.38
TRNP NORTH UNIT												
2000												
Largest Delta-DV	3.286	5.520	2.234	2000	36	82	71	2.8	6.07	93.33	0.40	0.20
98th %tile Delta-DV	1.199	3.432	2.234	2000	74	67	56	2.8	11.50	88.29	0.09	0.12
90th %tile Delta-DV	0.241	2.368	2.127	2000	301	63	52	2.3	1.91	96.26	1.38	0.45
2001												
Largest Delta-DV	2.801	4.929	2.127	2001	98	62	51	2.3	8.18	90.90	0.68	0.23
98th %tile Delta-DV	1.314	3.547	2.234	2001	43	82	71	2.8	10.44	89.04	0.39	0.13
90th %tile Delta-DV	0.214	2.320	2.106	2001	254	83	112	2.2	20.20	76.56	2.35	0.89
2002												
Largest Delta-DV	5.781	8.015	2.234	2002	73	63	52	2.8	7.08	92.45	0.35	0.12
98th %tile Delta-DV	2.464	4.697	2.234	2002	75	82	71	2.8	9.38	90.15	0.30	0.17
90th %tile Delta-DV	0.359	2.529	2.170	2002	159	78	67	2.5	8.35	89.00	1.75	0.90
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	3.182	5.416	2.234	2000	74	90	72	2.8	11.99	87.79	0.10	0.12
98th %tile Delta-DV	0.827	2.976	2.149	2000	184	90	72	2.4	32.57	64.75	1.96	0.72
90th %tile Delta-DV	0.175	2.345	2.170	2000	164	90	72	2.5	46.62	50.12	2.29	0.97
2001												
Largest Delta-DV	1.918	4.046	2.127	2001	92	90	72	2.3	4.10	95.38	0.37	0.15
98th %tile Delta-DV	0.863	2.969	2.106	2001	258	90	72	2.2	28.24	70.13	1.23	0.40
90th %tile Delta-DV	0.119	2.225	2.106	2001	248	90	72	2.2	64.38	30.48	3.36	1.77
2002												
Largest Delta-DV	6.606	8.840	2.234	2002	73	90	72	2.8	7.79	91.76	0.33	0.12
98th %tile Delta-DV	2.601	4.856	2.255	2002	29	90	72	2.9	8.06	91.59	0.25	0.10
90th %tile Delta-DV	0.219	2.325	2.106	2002	270	90	72	2.2	5.80	93.28	0.68	0.24
LOSTWOOD NWA												
2000												
Largest Delta-DV	3.905	6.180	2.275	2000	47	97	79	2.9	10.64	89.04	0.21	0.10
98th %tile Delta-DV	1.311	3.586	2.275	2000	48	99	81	2.9	10.41	89.34	0.16	0.09
90th %tile Delta-DV	0.421	2.567	2.145	2000	114	91	73	2.3	17.32	80.96	1.02	0.69
2001												
Largest Delta-DV	5.734	8.074	2.340	2001	327	99	81	3.2	9.14	90.57	0.19	0.11
98th %tile Delta-DV	1.654	3.929	2.275	2001	89	93	75	2.9	8.09	91.40	0.36	0.15
90th %tile Delta-DV	0.450	2.617	2.167	2001	304	93	75	2.4	4.84	94.03	0.90	0.24
2002												
Largest Delta-DV	2.845	5.121	2.275	2002	74	97	79	2.9	10.80	88.92	0.18	0.10
98th %tile Delta-DV	1.343	3.618	2.275	2002	69	99	81	2.9	5.46	94.25	0.16	0.13
90th %tile Delta-DV	0.344	2.555	2.211	2002	172	99	81	2.6	25.57	69.53	3.68	1.22

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 14
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 33
Number of days with Delta-Deciview > 1.00: 22
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 32
Number of days with Delta-Deciview > 1.00: 22
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 31
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 34
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 15
Max number of consecutive days with Delta-Deciview > 0.50: 3

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 3A
2000-2002

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	4.878	7.111	2.234	2000	74	51	105	2.8	69.15	30.81	0.02	0.02
98th %tile Delta-DV	1.464	3.740	2.276	2000	316	46	46	3.0	60.13	39.82	0.04	0.01
90th %tile Delta-DV	0.412	2.518	2.106	2000	214	46	46	2.2	97.63	2.18	0.15	0.05
2001												
Largest Delta-DV	3.145	5.251	2.106	2001	260	46	46	2.2	94.80	5.09	0.08	0.03
98th %tile Delta-DV	1.576	3.725	2.149	2001	205	51	105	2.4	84.26	15.47	0.21	0.06
90th %tile Delta-DV	0.373	2.479	2.106	2001	224	53	107	2.2	96.76	3.06	0.14	0.04
2002												
Largest Delta-DV	6.961	9.194	2.234	2002	78	53	107	2.8	72.32	27.63	0.03	0.02
98th %tile Delta-DV	3.552	5.807	2.255	2002	26	48	102	2.9	59.46	40.46	0.06	0.02
90th %tile Delta-DV	0.611	2.844	2.234	2002	91	56	110	2.8	63.16	36.81	0.01	0.01
TRNP NORTH UNIT												
2000												
Largest Delta-DV	3.135	5.368	2.234	2000	72	82	71	2.8	61.67	38.26	0.05	0.02
98th %tile Delta-DV	1.469	3.575	2.106	2000	217	82	71	2.2	81.65	18.26	0.07	0.03
90th %tile Delta-DV	0.373	2.501	2.127	2000	286	82	71	2.3	58.48	41.43	0.06	0.03
2001												
Largest Delta-DV	4.011	6.244	2.234	2001	64	82	71	2.8	73.23	26.73	0.03	0.01
98th %tile Delta-DV	1.853	3.959	2.106	2001	234	82	71	2.2	98.06	1.77	0.13	0.04
90th %tile Delta-DV	0.488	2.615	2.127	2001	112	58	47	2.3	51.71	48.11	0.15	0.04
2002												
Largest Delta-DV	6.257	8.490	2.234	2002	73	63	52	2.8	58.28	41.64	0.06	0.02
98th %tile Delta-DV	3.026	5.259	2.234	2002	51	82	71	2.8	64.37	35.56	0.04	0.02
90th %tile Delta-DV	0.639	2.766	2.127	2002	138	82	71	2.3	61.20	38.60	0.14	0.06
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	4.342	6.576	2.234	2000	74	90	72	2.8	71.00	28.97	0.01	0.02
98th %tile Delta-DV	1.084	3.317	2.234	2000	69	90	72	2.8	54.54	45.37	0.06	0.03
90th %tile Delta-DV	0.341	2.469	2.127	2000	139	90	72	2.3	85.26	14.66	0.05	0.03
2001												
Largest Delta-DV	2.795	5.029	2.234	2001	64	90	72	2.8	76.35	23.62	0.03	0.01
98th %tile Delta-DV	1.321	3.555	2.234	2001	84	90	72	2.8	56.81	43.10	0.06	0.03
90th %tile Delta-DV	0.239	2.473	2.234	2001	55	90	72	2.8	59.90	40.06	0.03	0.01
2002												
Largest Delta-DV	7.443	9.677	2.234	2002	73	90	72	2.8	60.67	39.25	0.06	0.02
98th %tile Delta-DV	2.783	5.017	2.234	2002	39	90	72	2.8	78.00	21.88	0.08	0.04
90th %tile Delta-DV	0.404	2.531	2.127	2002	125	90	72	2.3	55.44	44.52	0.01	0.03
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.473	6.748	2.275	2000	47	97	79	2.9	83.69	16.26	0.04	0.02
98th %tile Delta-DV	1.685	3.960	2.275	2000	70	93	75	2.9	50.80	49.11	0.06	0.03
90th %tile Delta-DV	0.660	2.805	2.145	2000	131	93	75	2.3	57.84	42.02	0.12	0.03
2001												
Largest Delta-DV	5.789	8.129	2.340	2001	327	99	81	3.2	64.91	35.04	0.03	0.02
98th %tile Delta-DV	2.227	4.566	2.340	2001	333	99	81	3.2	64.47	35.44	0.05	0.04
90th %tile Delta-DV	0.596	2.742	2.145	2001	107	97	79	2.3	44.73	55.14	0.09	0.04
2002												
Largest Delta-DV	3.766	6.041	2.275	2002	74	97	79	2.9	68.87	31.09	0.03	0.01
98th %tile Delta-DV	2.195	4.427	2.232	2002	205	91	73	2.7	82.94	16.95	0.08	0.03
90th %tile Delta-DV	0.504	2.800	2.297	2002	31	97	79	3.0	78.62	21.36	0.01	0.01

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 31
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 43
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 35
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 42
Number of days with Delta-Deciview > 1.00: 28
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 34
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 44
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 45
Number of days with Delta-Deciview > 1.00: 25
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 38
Number of days with Delta-Deciview > 1.00: 23
Max number of consecutive days with Delta-Deciview > 0.50: 4

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 3B
2000-2002

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	4.897	7.130	2.234	2000	74	51	105	2.8	69.17	30.76	0.03	0.03
98th %tile Delta-DV	1.464	3.740	2.276	2000	316	46	46	3.0	60.09	39.80	0.08	0.03
90th %tile Delta-DV	0.413	2.519	2.106	2000	214	46	46	2.2	97.44	2.18	0.29	0.09
2001												
Largest Delta-DV	3.153	5.259	2.106	2001	260	46	46	2.2	94.72	5.07	0.15	0.06
98th %tile Delta-DV	1.581	3.729	2.149	2001	205	51	105	2.4	84.03	15.43	0.43	0.11
90th %tile Delta-DV	0.373	2.479	2.106	2001	224	53	107	2.2	96.59	3.05	0.28	0.09
2002												
Largest Delta-DV	6.957	9.191	2.234	2002	78	53	107	2.8	71.90	28.00	0.06	0.04
98th %tile Delta-DV	3.568	5.823	2.255	2002	26	48	102	2.9	59.40	40.45	0.12	0.04
90th %tile Delta-DV	0.612	2.846	2.234	2002	91	56	110	2.8	63.14	36.81	0.02	0.03
TRNP NORTH UNIT												
2000												
Largest Delta-DV	3.152	5.386	2.234	2000	72	82	71	2.8	61.59	38.27	0.10	0.03
98th %tile Delta-DV	1.471	3.577	2.106	2000	217	82	71	2.2	81.57	18.24	0.13	0.06
90th %tile Delta-DV	0.372	2.500	2.127	2000	286	82	71	2.3	58.45	41.37	0.13	0.05
2001												
Largest Delta-DV	4.019	6.253	2.234	2001	64	82	71	2.8	73.17	26.75	0.06	0.02
98th %tile Delta-DV	1.856	3.962	2.106	2001	234	82	71	2.2	97.90	1.76	0.26	0.08
90th %tile Delta-DV	0.496	2.623	2.127	2001	112	58	47	2.3	51.62	48.01	0.29	0.07
2002												
Largest Delta-DV	6.269	8.503	2.234	2002	73	63	52	2.8	58.22	41.61	0.13	0.04
98th %tile Delta-DV	3.033	5.266	2.234	2002	51	82	71	2.8	64.29	35.58	0.09	0.04
90th %tile Delta-DV	0.641	2.769	2.127	2002	138	82	71	2.3	61.01	38.59	0.28	0.11
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	4.360	6.593	2.234	2000	74	90	72	2.8	70.99	28.95	0.03	0.03
98th %tile Delta-DV	1.084	3.318	2.234	2000	69	90	72	2.8	54.49	45.33	0.13	0.06
90th %tile Delta-DV	0.340	2.467	2.127	2000	139	90	72	2.3	85.21	14.62	0.11	0.06
2001												
Largest Delta-DV	2.798	5.031	2.234	2001	64	90	72	2.8	76.31	23.62	0.05	0.02
98th %tile Delta-DV	1.322	3.556	2.234	2001	84	90	72	2.8	56.76	43.06	0.12	0.05
90th %tile Delta-DV	0.241	2.369	2.127	2001	147	90	72	2.3	94.64	5.14	0.16	0.06
2002												
Largest Delta-DV	7.463	9.697	2.234	2002	73	90	72	2.8	60.61	39.23	0.12	0.04
98th %tile Delta-DV	2.795	5.029	2.234	2002	39	90	72	2.8	78.17	21.59	0.15	0.09
90th %tile Delta-DV	0.402	2.529	2.127	2002	125	90	72	2.3	55.41	44.51	0.02	0.07
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.440	6.715	2.275	2000	47	97	79	2.9	82.72	17.17	0.08	0.04
98th %tile Delta-DV	1.686	3.961	2.275	2000	70	93	75	2.9	50.75	49.07	0.12	0.06
90th %tile Delta-DV	0.661	2.807	2.145	2000	131	97	79	2.3	59.10	40.58	0.25	0.07
2001												
Largest Delta-DV	5.865	8.204	2.340	2001	327	99	81	3.2	64.90	35.01	0.07	0.03
98th %tile Delta-DV	2.229	4.569	2.340	2001	333	99	81	3.2	64.39	35.43	0.10	0.07
90th %tile Delta-DV	0.597	2.742	2.145	2001	107	97	79	2.3	44.68	55.07	0.17	0.08
2002												
Largest Delta-DV	3.788	6.063	2.275	2002	74	97	79	2.9	68.85	31.07	0.05	0.03
98th %tile Delta-DV	2.180	4.519	2.340	2002	312	99	81	3.2	65.40	34.47	0.07	0.06
90th %tile Delta-DV	0.516	2.813	2.297	2002	31	97	79	3.0	78.58	21.38	0.02	0.01

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 31
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 43
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 35
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 42
Number of days with Delta-Deciview > 1.00: 28
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 34
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 44
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 45
Number of days with Delta-Deciview > 1.00: 25
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 38
Number of days with Delta-Deciview > 1.00: 23
Max number of consecutive days with Delta-Deciview > 0.50: 4

Minnkota Power Cooperative
Milton R. Young Unit 2
BART Run 3
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	5.577	7.811	2.234	2000	74	51	105	2.8	54.92	44.99	0.05	0.05
98th %tile Delta-DV	1.647	3.817	2.170	2000	152	54	108	2.5	36.38	62.85	0.57	0.20
90th %tile Delta-DV	0.511	2.638	2.127	2000	101	47	101	2.3	34.53	65.12	0.23	0.12
2001												
Largest Delta-DV	3.297	5.530	2.234	2001	64	46	46	2.8	58.91	40.96	0.09	0.04
98th %tile Delta-DV	2.001	4.235	2.234	2001	84	46	46	2.8	40.75	59.03	0.15	0.06
90th %tile Delta-DV	0.397	2.503	2.106	2001	234	51	105	2.2	94.76	4.72	0.40	0.12
2002												
Largest Delta-DV	8.275	10.508	2.234	2002	73	48	102	2.8	44.60	55.19	0.15	0.05
98th %tile Delta-DV	4.338	6.444	2.106	2002	250	53	107	2.2	63.35	36.16	0.35	0.15
90th %tile Delta-DV	0.780	2.907	2.127	2002	294	47	101	2.3	42.15	57.47	0.26	0.12
TRNP NORTH UNIT												
2000												
Largest Delta-DV	3.754	5.988	2.234	2000	72	82	71	2.8	44.56	55.26	0.13	0.05
98th %tile Delta-DV	1.660	3.766	2.106	2000	217	82	71	2.2	68.22	31.49	0.20	0.09
90th %tile Delta-DV	0.421	2.570	2.149	2000	191	67	56	2.4	91.41	7.97	0.48	0.15
2001												
Largest Delta-DV	4.537	6.771	2.234	2001	64	82	71	2.8	57.23	42.65	0.09	0.04
98th %tile Delta-DV	2.082	4.188	2.106	2001	260	86	115	2.2	87.36	12.37	0.19	0.08
90th %tile Delta-DV	0.517	2.666	2.149	2001	205	58	47	2.4	92.58	6.69	0.54	0.19
2002												
Largest Delta-DV	7.694	9.928	2.234	2002	73	63	52	2.8	40.95	58.83	0.16	0.06
98th %tile Delta-DV	3.703	5.937	2.234	2002	75	82	71	2.8	49.80	49.97	0.14	0.08
90th %tile Delta-DV	0.773	3.006	2.234	2002	91	82	71	2.8	47.25	52.60	0.09	0.06
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	5.037	7.270	2.234	2000	74	90	72	2.8	55.53	44.39	0.04	0.05
98th %tile Delta-DV	1.497	3.730	2.234	2000	69	90	72	2.8	37.02	62.75	0.16	0.07
90th %tile Delta-DV	0.349	2.519	2.170	2000	152	90	72	2.5	53.35	46.14	0.35	0.16
2001												
Largest Delta-DV	3.117	5.350	2.234	2001	64	90	72	2.8	61.14	38.75	0.08	0.03
98th %tile Delta-DV	1.795	4.028	2.234	2001	84	90	72	2.8	39.07	60.70	0.15	0.07
90th %tile Delta-DV	0.272	2.399	2.127	2001	94	90	72	2.3	56.09	43.84	0.04	0.02
2002												
Largest Delta-DV	8.901	11.134	2.234	2002	73	90	72	2.8	43.67	56.12	0.16	0.05
98th %tile Delta-DV	3.057	5.291	2.234	2002	39	90	72	2.8	63.55	36.10	0.22	0.14
90th %tile Delta-DV	0.415	2.564	2.149	2002	198	90	72	2.4	93.95	5.38	0.47	0.20
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.587	6.862	2.275	2000	47	97	79	2.9	67.76	32.07	0.11	0.06
98th %tile Delta-DV	1.965	4.240	2.275	2000	55	91	73	2.9	67.87	31.96	0.09	0.08
90th %tile Delta-DV	0.810	3.085	2.275	2000	65	91	73	2.9	61.71	38.02	0.17	0.11
2001												
Largest Delta-DV	6.953	9.293	2.340	2001	327	99	81	3.2	47.65	52.21	0.09	0.04
98th %tile Delta-DV	2.731	5.070	2.340	2001	333	99	81	3.2	48.63	51.13	0.14	0.10
90th %tile Delta-DV	0.806	2.973	2.167	2001	240	91	73	2.4	70.59	29.06	0.23	0.11
2002												
Largest Delta-DV	4.457	6.732	2.275	2002	74	97	79	2.9	52.05	47.83	0.07	0.04
98th %tile Delta-DV	2.318	4.550	2.232	2002	205	91	73	2.7	71.61	28.05	0.25	0.09
90th %tile Delta-DV	0.601	2.768	2.167	2002	218	99	81	2.4	84.33	15.25	0.21	0.22

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 37
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 29
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 52
Number of days with Delta-Deciview > 1.00: 27
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 29
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 37
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 45
Number of days with Delta-Deciview > 1.00: 29
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 29
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 50
Number of days with Delta-Deciview > 1.00: 27
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 48
Number of days with Delta-Deciview > 1.00: 27
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 45
Number of days with Delta-Deciview > 1.00: 25
Max number of consecutive days with Delta-Deciview > 0.50: 4

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 4
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	1.269	3.502	2.234	2000	74	51	105	2.8	37.96	61.85	0.09	0.09
98th %tile Delta-DV	0.265	2.499	2.234	2000	69	56	110	2.8	23.55	75.98	0.35	0.13
90th %tile Delta-DV	0.094	2.221	2.127	2000	109	53	107	2.3	9.18	88.60	1.69	0.53
2001												
Largest Delta-DV	0.592	2.720	2.127	2001	112	51	105	2.3	23.91	75.37	0.57	0.15
98th %tile Delta-DV	0.344	2.620	2.276	2001	328	45	45	3	38.61	61.25	0.08	0.06
90th %tile Delta-DV	0.060	2.188	2.127	2001	101	45	45	2.3	50.01	49.86	0.07	0.06
2002												
Largest Delta-DV	2.023	4.256	2.234	2002	78	45	45	2.8	32.34	67.42	0.14	0.10
98th %tile Delta-DV	0.847	3.081	2.234	2002	64	54	108	2.8	28.28	71.37	0.22	0.13
90th %tile Delta-DV	0.118	2.246	2.127	2002	118	53	107	2.3	41.52	58.16	0.20	0.12
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.116	3.349	2.234	2000	36	82	71	2.8	22.10	77.41	0.33	0.16
98th %tile Delta-DV	0.342	2.469	2.127	2000	98	84	113	2.3	23.30	75.97	0.57	0.16
90th %tile Delta-DV	0.068	2.196	2.127	2000	286	82	71	2.3	28.79	70.86	0.22	0.13
2001												
Largest Delta-DV	0.849	3.082	2.234	2001	64	82	71	2.8	42.62	57.12	0.19	0.07
98th %tile Delta-DV	0.385	2.513	2.127	2001	109	63	52	2.3	22.79	76.20	0.74	0.28
90th %tile Delta-DV	0.079	2.185	2.106	2001	254	83	112	2.2	52.02	46.01	1.46	0.52
2002												
Largest Delta-DV	1.894	4.128	2.234	2002	73	63	52	2.8	26.80	72.76	0.33	0.11
98th %tile Delta-DV	0.734	2.967	2.234	2002	75	82	71	2.8	32.58	67.06	0.23	0.13
90th %tile Delta-DV	0.131	2.237	2.106	2002	248	82	71	2.2	39.07	60.31	0.39	0.23
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.042	3.276	2.234	2000	74	90	72	2.8	39.92	59.91	0.08	0.09
98th %tile Delta-DV	0.246	2.480	2.234	2000	69	90	72	2.8	24.81	74.77	0.29	0.13
90th %tile Delta-DV	0.059	2.165	2.106	2000	239	90	72	2.2	67.12	32.25	0.41	0.22
2001												
Largest Delta-DV	0.539	2.772	2.234	2001	64	90	72	2.8	46.77	53.00	0.16	0.07
98th %tile Delta-DV	0.304	2.538	2.234	2001	84	90	72	2.8	26.81	72.78	0.29	0.12
90th %tile Delta-DV	0.041	2.211	2.170	2001	153	90	72	2.5	63.10	35.53	0.99	0.38
2002												
Largest Delta-DV	2.175	4.409	2.234	2002	73	90	72	2.8	29.00	70.61	0.29	0.10
98th %tile Delta-DV	0.790	3.024	2.234	2002	39	90	72	2.8	32.31	67.19	0.32	0.18
90th %tile Delta-DV	0.071	2.198	2.127	2002	117	90	72	2.3	7.64	91.19	0.67	0.51
LOSTWOOD NWA												
2000												
Largest Delta-DV	1.446	3.721	2.275	2000	47	97	79	2.9	36.30	63.46	0.16	0.08
98th %tile Delta-DV	0.421	2.589	2.167	2000	217	91	73	2.4	58.25	40.61	0.85	0.28
90th %tile Delta-DV	0.139	2.479	2.340	2000	363	93	75	3.2	23.15	76.56	0.15	0.14
2001												
Largest Delta-DV	2.207	4.547	2.340	2001	327	99	81	3.2	32.49	67.26	0.16	0.09
98th %tile Delta-DV	0.517	2.857	2.340	2001	355	93	75	3.2	14.59	84.46	0.71	0.23
90th %tile Delta-DV	0.141	2.480	2.340	2001	314	99	81	3.2	19.49	80.24	0.16	0.11
2002												
Largest Delta-DV	0.857	3.133	2.275	2002	74	97	79	2.9	37.79	62.00	0.14	0.08
98th %tile Delta-DV	0.435	2.602	2.167	2002	239	93	75	2.4	56.71	42.83	0.32	0.14
90th %tile Delta-DV	0.102	2.248	2.145	2002	100	91	73	2.3	38.78	61.00	0.12	0.10

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 6
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

Minnkota Power Cooperative
Milton R. Young Unit 2
BART Run 4
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	2.255	4.489	2.234	2000	74	51	105	2.8	40.92	58.76	0.15	0.17
98th %tile Delta-DV	0.569	2.845	2.276	2000	316	46	46	3	31.91	67.61	0.35	0.13
90th %tile Delta-DV	0.159	2.287	2.127	2000	98	47	101	2.3	37.13	62.29	0.38	0.21
2001												
Largest Delta-DV	1.149	3.382	2.234	2001	64	46	46	2.8	47.43	52.13	0.31	0.13
98th %tile Delta-DV	0.667	2.900	2.234	2001	84	46	46	2.8	30.36	68.93	0.50	0.21
90th %tile Delta-DV	0.122	2.228	2.106	2001	248	48	102	2.2	87.52	10.40	1.33	0.76
2002												
Largest Delta-DV	3.621	5.854	2.234	2002	78	45	45	2.8	35.44	64.14	0.25	0.17
98th %tile Delta-DV	1.612	3.846	2.234	2002	64	54	108	2.8	31.00	68.38	0.38	0.24
90th %tile Delta-DV	0.238	2.366	2.127	2002	118	53	107	2.3	44.33	55.09	0.35	0.22
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.716	3.949	2.234	2000	36	82	71	2.8	25.66	73.41	0.63	0.30
98th %tile Delta-DV	0.687	2.921	2.234	2000	74	67	56	2.8	41.89	57.84	0.12	0.16
90th %tile Delta-DV	0.132	2.281	2.149	2000	187	58	47	2.4	90.71	7.99	0.83	0.47
2001												
Largest Delta-DV	1.644	3.877	2.234	2001	64	82	71	2.8	45.70	53.86	0.31	0.13
98th %tile Delta-DV	0.706	2.833	2.127	2001	109	58	47	2.3	26.13	72.08	1.27	0.52
90th %tile Delta-DV	0.162	2.268	2.106	2001	230	82	71	2.2	86.55	10.92	1.72	0.80
2002												
Largest Delta-DV	3.194	5.427	2.234	2002	73	63	52	2.8	29.97	69.30	0.54	0.19
98th %tile Delta-DV	1.397	3.630	2.234	2002	75	82	71	2.8	35.54	63.80	0.42	0.24
90th %tile Delta-DV	0.213	2.341	2.127	2002	110	82	71	2.3	48.55	50.84	0.42	0.18
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.926	4.160	2.234	2000	74	90	72	2.8	43.05	56.66	0.13	0.16
98th %tile Delta-DV	0.487	2.720	2.234	2000	69	90	72	2.8	27.15	72.11	0.51	0.23
90th %tile Delta-DV	0.097	2.225	2.127	2000	110	90	72	2.3	8.76	86.96	3.19	1.10
2001												
Largest Delta-DV	1.066	3.299	2.234	2001	64	90	72	2.8	49.81	49.79	0.28	0.12
98th %tile Delta-DV	0.594	2.827	2.234	2001	84	90	72	2.8	29.11	70.18	0.50	0.22
90th %tile Delta-DV	0.082	2.358	2.276	2001	345	90	72	3	39.25	59.94	0.61	0.20
2002												
Largest Delta-DV	3.812	6.046	2.234	2002	73	90	72	2.8	31.97	67.35	0.50	0.18
98th %tile Delta-DV	1.447	3.680	2.234	2002	39	90	72	2.8	37.08	61.97	0.59	0.35
90th %tile Delta-DV	0.133	2.282	2.149	2002	189	90	72	2.4	90.95	6.52	1.77	0.76
LOSTWOOD NWA												
2000												
Largest Delta-DV	2.302	4.577	2.275	2000	47	97	79	2.9	39.98	59.59	0.29	0.14
98th %tile Delta-DV	0.731	3.007	2.275	2000	48	99	81	2.9	39.13	60.53	0.22	0.12
90th %tile Delta-DV	0.264	2.604	2.340	2000	359	97	79	3.2	21.84	77.89	0.13	0.14
2001												
Largest Delta-DV	3.339	5.679	2.340	2001	327	99	81	3.2	35.97	63.60	0.28	0.16
98th %tile Delta-DV	0.863	3.138	2.275	2001	89	99	81	2.9	34.01	65.28	0.49	0.22
90th %tile Delta-DV	0.264	2.409	2.145	2001	96	99	81	2.3	34.38	63.87	1.21	0.55
2002												
Largest Delta-DV	1.635	3.910	2.275	2002	74	97	79	2.9	40.73	58.89	0.24	0.14
98th %tile Delta-DV	0.756	3.031	2.275	2002	76	99	81	2.9	33.01	65.91	0.83	0.25
90th %tile Delta-DV	0.201	2.476	2.275	2002	52	97	79	2.9	41.69	58.00	0.19	0.12

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 16
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 3

Minnkota Power Cooperative
Milton R. Young Unit 1 & 2
BART Run 5
2000-2002

						SEQ	ND	% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	3.279	5.513	2.234	2000	74	51	105	2.8	39.91	59.82	0.13	0.14
98th %tile Delta-DV	0.817	3.092	2.276	2000	316	45	45	3	31.35	68.24	0.30	0.11
90th %tile Delta-DV	0.241	2.369	2.127	2000	109	53	107	2.3	9.98	86.72	2.50	0.80
2001												
Largest Delta-DV	1.671	3.905	2.234	2001	64	46	46	2.8	46.41	53.21	0.27	0.11
98th %tile Delta-DV	0.987	3.221	2.234	2001	84	46	46	2.8	29.56	69.83	0.43	0.18
90th %tile Delta-DV	0.179	2.285	2.106	2001	248	48	102	2.2	87.47	10.70	1.17	0.66
2002												
Largest Delta-DV	5.058	7.291	2.234	2002	78	45	45	2.8	34.50	65.14	0.21	0.15
98th %tile Delta-DV	2.336	4.569	2.234	2002	64	54	108	2.8	30.11	69.36	0.33	0.21
90th %tile Delta-DV	0.354	2.481	2.127	2002	118	53	107	2.3	43.40	56.11	0.30	0.19
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.656	4.889	2.234	2000	36	82	71	2.8	24.37	74.87	0.51	0.25
98th %tile Delta-DV	0.979	3.212	2.234	2000	74	67	56	2.8	40.71	59.06	0.10	0.14
90th %tile Delta-DV	0.200	2.434	2.234	2000	65	82	71	2.8	34.83	63.06	1.36	0.75
2001												
Largest Delta-DV	2.367	4.601	2.234	2001	64	82	71	2.8	44.70	54.92	0.27	0.11
98th %tile Delta-DV	1.058	3.186	2.127	2001	109	58	47	2.3	25.40	73.08	1.08	0.44
90th %tile Delta-DV												
2002												
Largest Delta-DV	4.597	6.831	2.234	2002	73	63	52	2.8	28.90	70.47	0.46	0.16
98th %tile Delta-DV	2.031	4.265	2.234	2002	75	82	71	2.8	34.66	64.78	0.36	0.20
90th %tile Delta-DV	0.330	2.500	2.170	2002	154	82	71	2.5	45.03	54.16	0.59	0.23
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	2.791	5.025	2.234	2000	74	90	72	2.8	42.02	57.73	0.11	0.14
98th %tile Delta-DV	0.721	2.954	2.234	2000	69	90	72	2.8	26.39	72.98	0.43	0.20
90th %tile Delta-DV	0.178	2.454	2.276	2000	316	90	72	3	30.15	69.40	0.33	0.12
2001												
Largest Delta-DV	1.551	3.784	2.234	2001	64	90	72	2.8	48.82	50.84	0.24	0.10
98th %tile Delta-DV	0.880	3.113	2.234	2001	84	90	72	2.8	28.37	71.02	0.43	0.19
90th %tile Delta-DV	0.126	2.296	2.170	2001	153	90	72	2.5	64.15	33.83	1.44	0.57
2002												
Largest Delta-DV	5.337	7.570	2.234	2002	73	90	72	2.8	31.03	68.39	0.43	0.15
98th %tile Delta-DV	2.020	4.254	2.234	2002	39	90	72	2.8	37.65	61.51	0.53	0.31
90th %tile Delta-DV	0.195	2.343	2.149	2002	189	90	72	2.4	91.03	6.75	1.56	0.66
LOSTWOOD NWA												
2000												
Largest Delta-DV	3.458	5.734	2.275	2000	47	97	79	2.9	38.71	60.93	0.24	0.12
98th %tile Delta-DV	1.161	3.437	2.275	2000	37	97	79	2.9	23.36	76.08	0.37	0.18
90th %tile Delta-DV	0.393	2.669	2.275	2000	67	97	79	2.9	36.18	63.42	0.25	0.14
2001												
Largest Delta-DV	4.964	7.304	2.340	2001	327	99	81	3.2	34.66	64.98	0.23	0.13
98th %tile Delta-DV	1.332	3.608	2.275	2001	89	93	75	2.9	31.34	68.02	0.45	0.19
90th %tile Delta-DV	0.411	2.751	2.340	2001	314	99	81	3.2	20.85	78.74	0.24	0.17
2002												
Largest Delta-DV	2.366	4.642	2.275	2002	74	97	79	2.9	39.77	59.90	0.21	0.12
98th %tile Delta-DV	1.140	3.285	2.145	2002	131	99	81	2.3	30.86	67.70	1.10	0.34
90th %tile Delta-DV	0.303	2.578	2.275	2002	52	97	79	2.9	40.58	59.15	0.17	0.10

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 26
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 15
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 28
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 28
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 4

Appendix B

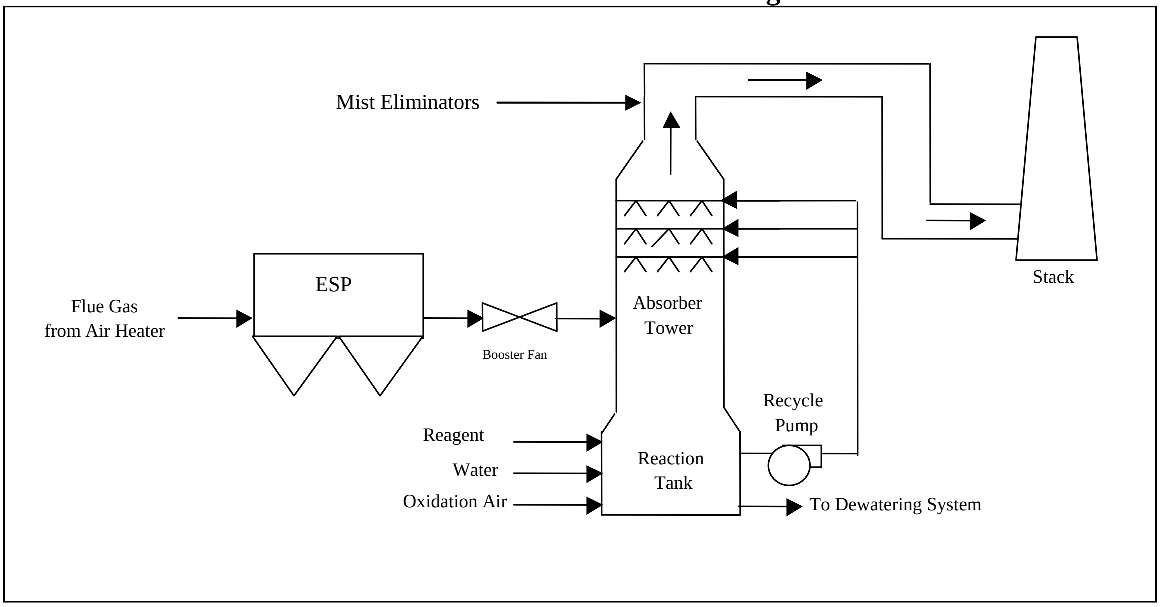
Detailed Description of SO_2 Control Technologies

Conventional Wet Scrubber (Wet FGD)

Wet FGD technology utilizing lime or limestone as the reagent and employing forced oxidation to produce gypsum (calcium sulfate dihydrate, $CaSO_4 \cdot 2H_2O$) as the byproduct, is a common method of SO_2 control for coal-fired boilers. The gypsum byproduct is either landfilled or sold for commercial reuse.

A flow diagram of the wet FGD process is provided in the below figure. In the wet FGD process, a slurry of finely ground reagent (typically limestone or lime) in water is recirculated through an absorber tower where it is brought into turbulent contact with the flue gas. The contact between the flue gas and the slurry cools and saturates the gas via evaporation of water from the slurry. SO_2 is simultaneously absorbed into the slurry where it forms sulfurous acid which reacts with the reagent, forming calcium sulfite hemihydrate ($CaSO_3 \bullet ½H_2O$), which can then be disposed of as a waste product or oxidized to calcium sulfate dihydrate, or gypsum, ($CaSO_4 \bullet 2H_2O$) before disposal or for commercial reuse. No commercial uses for sulfite waste products have been identified. Disposal of the sulfite waste can be somewhat difficult because of the thixotropic nature of the material. Sulfite wastes are often combined with fly ash to form a more easily handled waste solid. Disposal of the sulfate, or gypsum, as a waste is a bit more straightforward. The gypsum, depending upon its cleanliness, can be sold as a raw material for the manufacture of wallboard or cement. Where a gypsum product is desired, the most common approach is to sparge the reaction tank, or a separate holding tank with compressed air to convert the sulfite waste. Such systems are often referred to as Limestone Forced Oxidation (LSFO) systems.

Wet FGD Process Flow Diagram



In a limestone scrubber, as the limestone in the recirculating slurry is depleted, it is replenished with fresh slurry prepared by wet grinding of crushed limestone using reclaimed liquid from the dewatering system. Fresh water is also required to replace water lost to evaporation in the flue gas cooling process. Fresh water is often used to wash the mist eliminators; devices located at the scrubber exit to capture slurry droplets entrained in the exiting flue gas stream and return them to the scrubber. The mist eliminator wash removes accumulated materials from the mist eliminator chevrons, thus preventing solids buildup and pluggage. In addition, depending upon the mineral content of the coal, a portion of the reclaimed liquid may be blown down, or disposed of, to prevent excessive accumulation of mineral salts in the slurry which could result in mineral scaling or corrosion within the absorber equipment. The blow down rate varies with each plant. Fresh water makeup, both through the mist eliminator wash system and in the limestone grinding process, replaces the blow down and evaporative losses.

Lime scrubbers are very similar to limestone scrubbers. The use of lime rather than limestone can reduce the liquid-to-gas ratio and/or absorber size required to achieve a given SO_2 removal rate. Lime is sometimes used in wet FGD systems where extremely high SO_2 removal rates are desired or where limestone is not readily available. However, since lime is more expensive than limestone, the reagent cost is much higher for a lime system. Therefore, the vast majority of wet FGD systems are designed to use limestone as the neutralizing reagent.

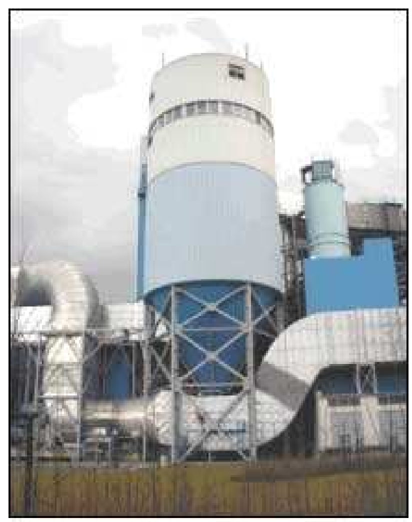
Advantages of the wet FGD systems include lower operating costs, primarily due to the ability to use limestone instead of lime as a reagent, the production of a salable by-product and high removal efficiency. Also, wet FGD systems have a high turndown capability and plant operational flexibility is not hindered to the same degree as the semi-dry, CFB and FDA processes. This last advantage is important where wet FGD systems are applied to load following units.

Disadvantages of wet FGD systems include corrosion due to a wet environment with corrosive chemicals including salts of sulfurous and sulfuric acid and hydrochloric acid. Also, because the wet systems are more mechanically complex, they typically require larger maintenance staff than some of the other alternatives. The greater mechanical complexity also contributes to a greater capital cost for wet FGD systems. Finally, because wet FGD systems completely saturate the flue gas stream, nearly all the SO_3 or H_2SO_4 vapor in the entering flue gas is condensed into aerosol droplets which are too small to be efficiently captured in the scrubber. Fifty percent or more of these droplets pass through the scrubber. Where units are burning high sulfur fuels, this can cause a plume opacity problem.

Wet FGD systems saturate the flue gas stream with moisture and as a result, operate with a wet stack. Two problems can occur with a wet stack. The first is entrainment of condensed liquids from the stack liner interior. The pressure of the flue gas changes as it traverses the stack and additional moisture condenses as a result. Some of that condensation occurs on the interior of the stack liner because it is normally a bit cooler than the flue gas. The condensed liquid runs down the interior of the liner and a significant fraction can become entrained in the flue gas stream, especially where droplets gather on liner surface irregularities such as mortar joints between bricks. Wet stacks are typically designed to have full load flue gas velocities of no more than approximately 60 feet per second to combat this reentrainment.

Conventional Dry Scrubbers (Dry FGD)

As an alternative to wet FGD technology, the control of SO_2 emissions can be accomplished using semi-dry FGD technology. The most common semi-dry FGD system is the lime Spray Dryer Absorber (SDA) using a Fabric Filter (FF) for downstream particulate collection. The semi-dry FGD process became popular in the U.S. beginning in the late 1970s as a way to comply with the New Source Performance Standards (NSPS) for electric utility steam generating units for which construction commenced after September 18, 1978 (40 CFR Part 60, Subpart Da). These standards require that all new coal-fired electric utility boilers be equipped with a “continuous system of emission reduction” for SO_2. However, the standards allowed SO_2 removal efficiency as low as 70 percent for facilities burning low-sulfur coal. The semi-dry FGD process could meet this requirement, and was often selected as the SO_2 control technology for many new coal-fired power plants that were built in the 1970s and 1980s and designed to burn low-sulfur western coal. In the late 1980s and through the 1990s, most of the new coal-fired boilers built in the U.S. were for small Independent Power Producer (IPP) projects, and many of these also selected the semi-dry FGD process.

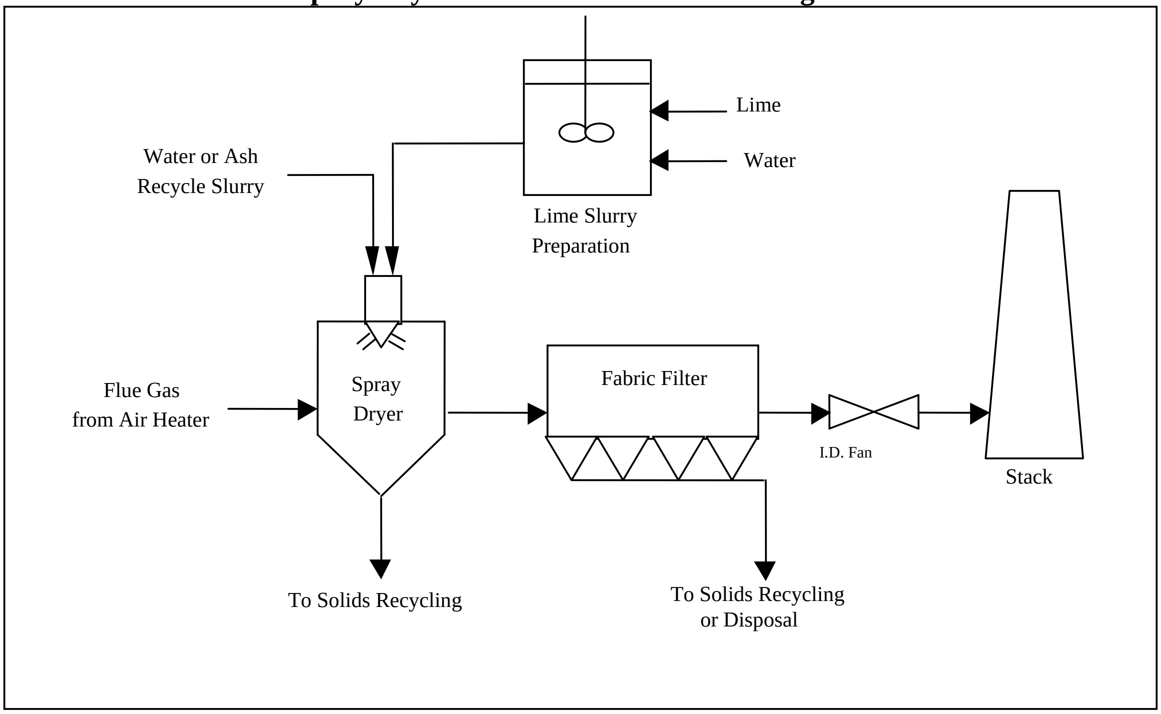

Typical SDA at a 533 MWe power plant in the Czech Republic.

Spray Dryer Absorber

There are several variations of the semi-dry process in use today. This section addresses the spray dryer absorber (SDA) process. Two other variations, the Flash Dryer Absorber (FDA) and Circulating Fluidized Bed (CFB) Scrubber are addressed in following sections. They primarily differ by the type of reactor vessel used, the method in which water and lime are introduced into the reactor and the degree of solids recycling.

A schematic diagram of the spray dryer absorber process is provided in the below figure. In the spray dryer absorber process, boiler flue gas is introduced into a Spray Dryer Absorber (SDA) into which hydrated lime (calcium hydroxide, $Ca(OH)_2$) and water are added as dispersed droplets. The $Ca(OH)_2$ reacts with SO_2 that has been absorbed into the water to form primarily calcium sulfite and some calcium sulfate. The heat from the flue gas causes the water to evaporate, cooling the gas and drying the reaction products. Because the total water feed rate is much lower than that of the wet FGD process, the reaction products are dried in the SDA and the flue gas is only partially saturated. The amount of water added to the process is carefully controlled so that the flue gas temperature is maintained well above the saturation, or dewpoint, temperature (typically 30-40 ^{0}F above saturation) to avoid corrosion problems. Cooling the gas to this point significantly increases the SO_2 control efficiency over injection of lime into hot, dry flue gas. The reaction product leaves the SDA as fine dry particles entrained in the flue gas. The flue gas enters the SDA at the top and flows downward, co-current with the introduced lime slurry. This characteristic is the opposite of the wet FGD system which introduces flue gas into the bottom of the absorber, countercurrent to the falling slurry spray.

Spray Dryer Absorber Process Flow Diagram



In the lime spray drying process, quicklime (CaO) is slaked with water to form lime slurry which is then injected into the SDA along with additional water through a rotary atomizer or dual fluid nozzle or similar apparatus. Recycled particulate matter (PM) from the PM control equipment downstream of the SDA is often mixed with the lime slurry before injection into the SDA to provide additional surface area for SO_2 absorption. The flue gas is introduced into the SDA in a manner designed to maximize the contact between the gas and the droplets and to prevent slurry impingement on the walls of the SDA. The turbulent mixing of the flue gas and the slurry droplets promotes rapid absorption of SO_2 into the water of the slurry droplets. The chemical reactions between the absorbed SO_2 and the calcium hydroxide take place within the droplet as the flue gas moves through the SDA. The flue gas is cooled and partially humidified as the water evaporates, leaving a mixture of fly ash and dry powdered reaction product entrained in the flue gas. Some of the solid particles fall to the bottom of the reactor and are collected by a waste handling system. Entrained particles are collected in an electrostatic precipitator (ESP) or fabric filter (FF) downstream of the SDA.

An additional distinguishing characteristic of the SDA is that it must be located upstream of a particulate control device, as opposed to the wet FGD process which is normally the last flue gas treatment process before discharge to the stack. For new plants, this point is not of such great importance. However, when retrofitting FGD equipment to an existing coal-fired plant, which already has particulate control equipment installed, this becomes an important point. If a suitable location exists for the insertion of a new SDA upstream of an existing PM control device, and if the performance of the existing PM control device would not be overly degraded by the additional PM loading, then the retrofit process would consist only of installation of the SDA, reagent preparation and waste handling systems. However, many times one, or both, of these conditions do not exist and the choice to utilize an SDA requires the installation of a new PM control device, such as an ESP or fabric filter. Where this situation exists, the capital cost of the SDA option increases significantly.

Semi-dry processes have some notable advantages compared to wet FGD processes including a dry byproduct which can be handled with conventional ash handling systems. Because the semi-dry system does not have a truly wet zone, corrosion problems in the SDA are eliminated, or significantly reduced, to the point exotic materials of construction are not required. Spray dryer systems utilize less complex equipment resulting in a reduced capital cost and allowing somewhat smaller operations and maintenance staff. Where a fabric filter is utilized as the downstream particulate control device for a semi-dry process, the lime content of the filter cake on the fabric filter reacts with condensed SO_3 in the flue gas stream capturing and neutralizing much of the acid aerosol. Consequently, semi-dry FGD options, paired with a fabric filter for PM control, have very low emissions of acid aerosols.

The primary disadvantages of the lime spray dryer process make it less likely to be applied to large power plant boilers, especially those firing high-sulfur coal. The lime spray dryer requires the use of lime, which is typically much more expensive than limestone. While lime contains approximately 1.8 times more calcium than limestone on a mass basis, lime can cost up to five times more than limestone on a mass basis. Therefore, reagent costs for a lime based process are typically higher than a limestone-based process for a given application.

Wastes from semi-dry processes have very limited possibility for reuse due to fly ash contamination. Also, where fly ash might be sold for other uses, contamination with the semi-dry FGD reaction products typically eliminates commercial options for reuse. Where fly ash sales are to be maintained, a second PM control device would be required for the semi-dry FGD system exhaust stream, increasing both capital and O&M costs.

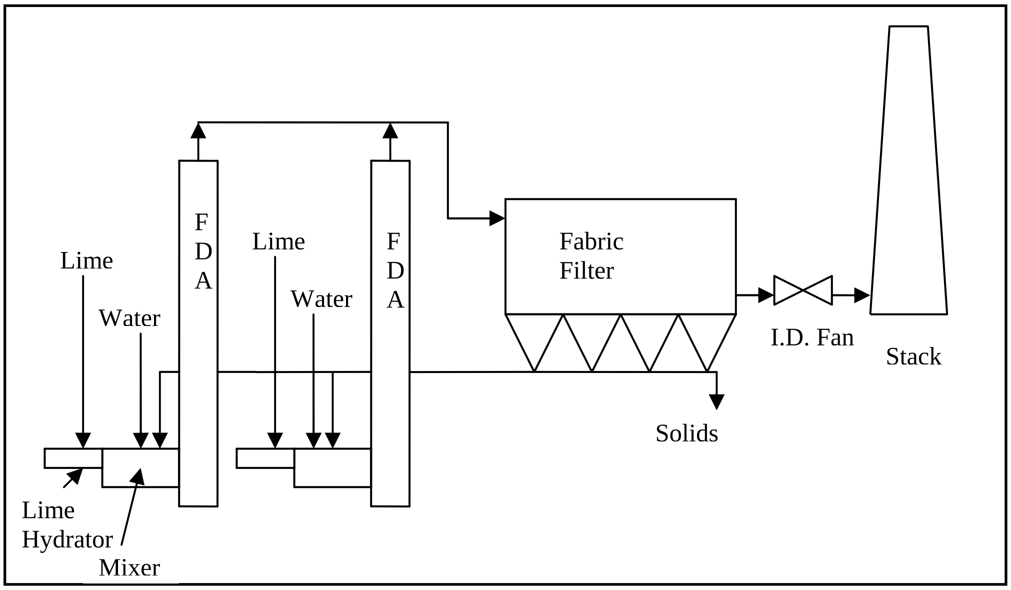
Spray dryer absorbers have much more stringent size limitations than wet FGD scrubbers. Typically units larger than 250 to 300 MW will require at least two SDA vessels, thus driving up capital costs and system complexity for larger units, while wet FGD systems can handle up to 1000 MW in a single absorber module. SDAs do not have the same turndown capabilities as wet FGD absorbers, further limiting applicability for load following units. Finally, lime spray dryer systems do not have the same level of experience with high SO_2 removal requirements in high sulfur applications that wet FGD systems have.

Flash Dryer Absorber

The Flash Dryer Absorber (FDA) is a further development of the lime spray dryer process. The approach is similar in that the flue gas is only partially saturated during the process and thus corrosion problems are either reduced or eliminated. Like the SDA, waste solids from the particulate control process can be added to the reagent feed stream to the reactor. Similar to the SDA, the FDA mixes lime, water and recycled PM for enhanced surface area. Recycled PM, along with absorption products and unreacted lime, are collected downstream of the FDA and a sizable fraction recycled to the FDA. Unlike the SDA, the FDA recycles a very high fraction of the captured PM. Because of this, the ratio of solids to liquid in the reagent stream injected into the FDA reactor is much higher than the SDA. The ratio is so much higher that the wetted recycled solids appear to be a relatively dry free flowing stream after wetting in the mixing stage.[14] Because the reagent stream starts off much higher in solids, the liquid film thickness on the wetted solids is much thinner and the drying time for the injected solids is much shorter than a typical SDA. This allows the FDA to function with a significantly smaller reactor compared to the typical SDA absorber vessel. Like the SDA, the water injection rate of the FDA is controlled to lower the flue gas temperature to optimize the SO_2 control efficiency while avoiding saturation and the accompanying corrosion problems. Unlike the SDA, the flue gas flows vertically upward in the FDA. The figure below is a schematic presentation of the FDA design.

[14] "Use of a Circulating Fluid Bed for Flue Gas Desulfurization"' Toher, John, G. Lurgi-Lentjes N. America.

Flash Dryer Absorber FGD Process Flow Diagram



The FDA utilizes quicklime (CaO) instead of hydrated lime as a reagent. The reasoning given for this by the designers is that when purchasing lime, although the price per ton is similar, the quicklime has 32% more calcium (SO_2 neutralization component) per ton than hydrated lime. Also, because quicklime is denser (900-1,200 kg/m^3 for quicklime vs. 450-640 kg/m^3 for hydrated lime), both transport and onsite storage capacity requirements can be smaller. However, direct injection of quicklime has resulted in less efficient reagent utilization compared to hydrated lime use. This is theorized to be due to hot spots created in the reaction zone by the hydration of the quicklime. The heat of hydration of quicklime is approximately 1.1 mmBtu/ton, so there is considerable heat evolved during the hydration step. To avoid adding this heat to the flue gas or creating hot spots that could reduce lime utilization, the FDA design incorporates a separate lime hydration stage where more than the stoichiometrically required amount of water is added to the quicklime in stages. The super stoichiometric water is heated during the slaking process and evaporates, leaving dry hydrated lime. The hydrated lime, recycled solids and water are then combined in a mixing vessel just prior to injection into the reactor.

Like the SDA, the FDA must be followed by a PM control device to capture the dry solids in the FDA exhaust. The great majority of these solids are recycled back to the FDA. The non recycled fraction is a mixture of calcium sulfite/sulfate solids, unreacted lime and fly ash for which limited possibilities for reuse exist. Also, in those instances where fly ash sales produce an income for the power plant, addition of the FDA solids to the fly ash will likely render the waste solids stream without value. Where the plant receives revenue from fly ash sales, the lost revenue would be an additional cost of FDA implementation.

The FDA is a relatively recent modification of the semi-dry FGD concept and as such, has not established a significant field record at this time. In their paper on FDA technology in 2002[15] Alstom cited a 280 MW plant in China with an 85% SO_2 removal efficiency. This plant had an FDA installed upstream of an ESP. Dry and semi-dry scrubbers installed upstream of a fabric filter have been consistently shown to achieve approximately 5-10% greater acid gas removal efficiency due to absorption and neutralization taking place in the filter cake of the fabric filter. Typically ESPs downstream of an FDA or other dry or semi-dry SO_2 scrubbing system are attributed no more than 5% SO_2 removal efficiency.

Advantages of the FDA over wet FGD systems are similar to those for the semi-dry process described previously, including ease of byproduct handling, much less aggressive corrosion conditions allowing the use of more common, less expensive materials of construction, less complex equipment, and potentially enhanced SO_3 control when combined with a fabric filter. FDA advantages also include a significantly smaller reactor/absorber which translates into a lower area requirement than either wet or semi-dry FGD systems, though manufacturers often provide multiple FDA's, even on smaller units.

Disadvantages of the FDA, when compared to the wet FGD system are similar to those described for the semi-dry process, including reactor size limitations, lower turndown ratio, more expensive reagent, and lack of byproduct market value.

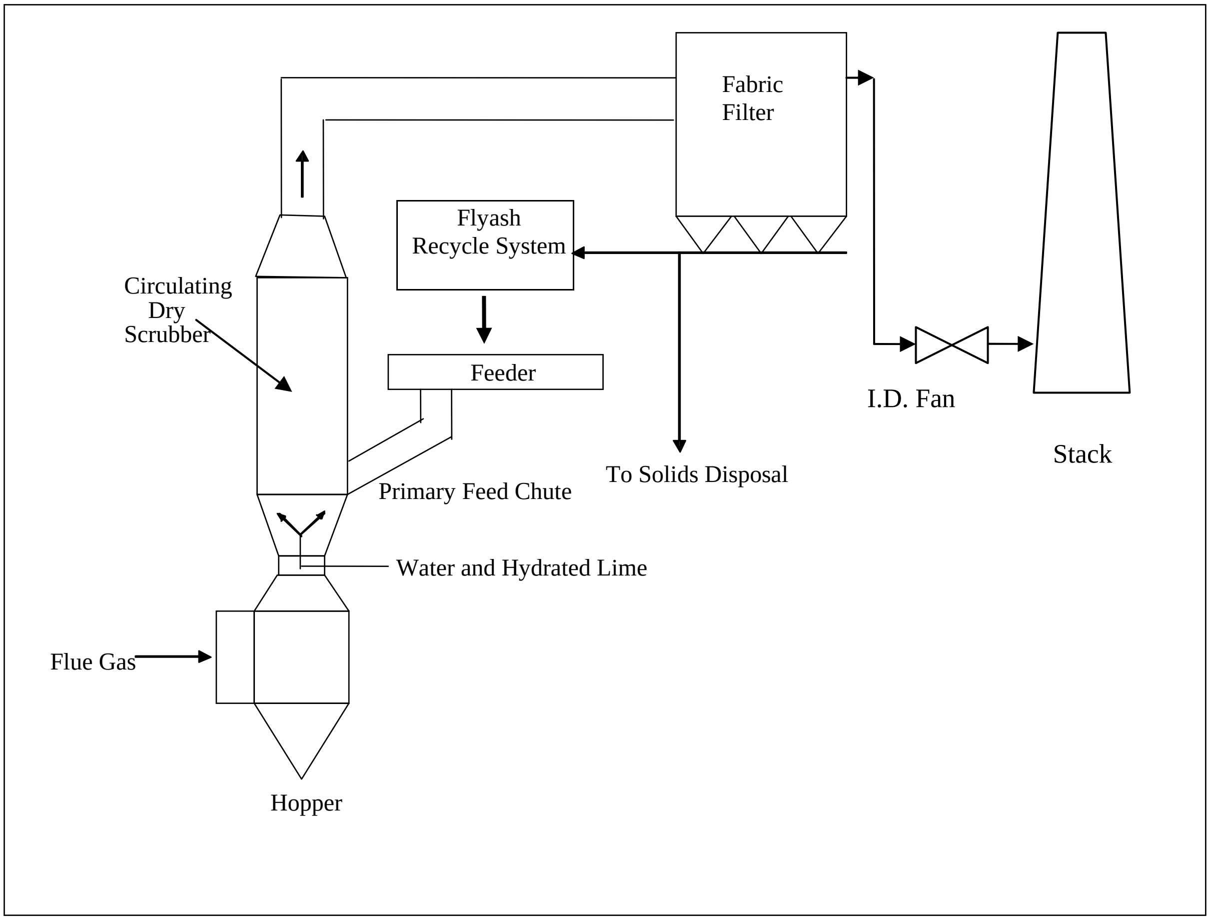
Circulating Fluidized Bed Absorber (CFB)

In the circulating fluidized bed dry scrubbing process, the flue gas is introduced into the bottom of a reactor vessel at high velocity through a venturi nozzle, and mixed with water, hydrated lime, recycled flyash and FGD reaction products. High velocity movement of the gas through the reactor suspends the solids creating a fluidized bed. A CFB absorber vessel would be a smaller diameter than the SDA discussed previously in this report. A schematic representation of the CFB process is shown in the below figure. The smaller diameter absorber helps maintain higher flue gas velocities required to maintain the fluidized bed. Water injected into the venturi throat cools the flue gas and wets the recycled solids similar to the process described previously for the FDA. Dry, powdered, hydrated lime is injected into the bed near the bottom of the absorber vessel, above the venturi, and dissolves in the thin water film on the recycled solids. SO_2 from the flue gas is also absorbed into the evaporating water film and reacts with the lime to produce both calcium sulfite and sulfate reaction products. Flue gas temperatures are typically

[15] "Alstom Power's Flash Dryer Absorber For Flue Gas Desulfurization", Ahman, Barranger and Marin, Proceedings of IJPGC '02, June 24-26, 2002.

reduced from 300 ^{0}F to approximately 160 ^{0}F to optimize SO_2 removal efficiency. The evaporation of the water cools and partially humidifies the flue gas and maintains the bed in a slightly moist, powdery condition. The continuous motion of the bed helps prevent solids deposition inside the absorber and promotes regeneration of the particle surfaces, exposing additional lime to react with absorbed SO_2. Particles that are entrained in the flue gas leaving the top of the reactor are collected in an ESP or fabric filter downstream of the CFB absorber. A large portion of the collected particles is recycled to the reactor, sustaining the bed and improving lime utilization. CFB absorbers have been installed with both fabric filters and ESPs for particulate control.

Circulating Fluidized Bed FGD System



The CFB absorber dry scrubbing process utilizes a bed of fluidized particles to provide an extended surface area for wetting, evaporation and SO_2 absorption. The extended surface decreases the time required for SO_2 absorption. Even though the gas velocity is higher than a wet FGD absorber or an SDA, the CFB absorber is not taller than either of these vessels.

The CFB has many of the same advantages of the SDA and FDA such as a dry byproduct, simplified waste handling systems and conventional materials of construction. CFBs also have less rotating equipment than wet FGD or SDA systems, thus simplifying maintenance requirements somewhat. Like the SDA and FDA, the CFB application with a fabric filter for particulate collection will also achieve very good acid aerosol control. Unlike the SDA the CFB does not require dual fluid nozzles or atomizers in the absorber. This feature simplifies the absorber maintenance of a CFB over that of the SDA. Also, because lime and water are injected separately into the CFB, increased reagent requirements can be met without increasing saturation of the flue gas.

Disadvantages of the CFB process include higher reagent cost and lower utilization than SDAs in similar applications and more limited turndown capability. In a recent study[16] the National Lime Association determined that compared to CFBs in similar applications, the SDA achieved slightly lower SO_2 removal with slightly better reagent utilization. Because CFBs must maintain gas velocities within a fluidizing range, a flue gas recycle duct from the absorber exhaust to the inlet is sometimes included to allow for partial recycle of flue gas to maintain bed velocity and improve the turndown ratio. Similar to the SDA and FDA processes, CFBs are size limited and multiple absorbers are required for applications larger than 250-300 MW.

An additional disadvantage of the CFB is pressure drop. Because the CFB must maintain the fluidized bed condition, the pressure drop across the absorber is typically 8-10 in. w.g. compared to an SDA at 6-8 in. w.g. and a wet FGD system at approximately 6 in. w.g.

Powerspan Electro-Catalytic Oxidation (ECO™) System

The Powerspan Electro-Catalytic Oxidation (ECO™) system is a multipollutant control technology designed to control emissions of NO_x, SO_2, fine particulate, mercury and certain Hazardous Air Pollutants (HAPs). The ECO™ process has two main process vessels, a barrier discharge reactor and a multi-level wet scrubber.

Powerspan is also making the technology available for systems that do not require NO_x removal by removing the barrier discharge reactor. Powerspan claims a routine SO_2 removal efficiency of 98% with inlet concentrations up to approximately 2,000 ppm.

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[16] "Economics of Lime and Limestone for Control of Sulfur Dioxide"; DePriest, William & Gaikwas, Rajendra P; National Lime Association (www.lime.org/NLADryFGD.PDF); September, 2002.

The system utilizes aqueous ammonia as a reagent in two scrubber loops, with varying pH to control collection efficiency in the lower and upper loops. The ammonia reacts with the collected SO_2 in aqueous solution to produce ammonium sulfate as a byproduct.

50-MW ECO Demo at FirstEnergy's R.E. Burger Plant

The ammonium sulfate is then salable as fertilizer, thus turning byproduct disposal into a profitable venture for system operators. Captured mercury and other oxidized metals are removed from the scrubber bleed stream with activated carbon and disposed of as a hazardous waste. Ash and insoluble metals are filtered from the scrubber bleed stream before fertilizer production and disposed of with other particulate wastes from upstream particulate control equipment. The ammonium sulfate can be sold as an aqueous product or crystallized, granulated and sold.

Appendix C

CUECost Model Input Summary

APC Technology Choices

Description	Units	Case 1	Case 2	Case 3	Case 4
FGD Process	Integer	1	2	1	1
(1 = LSFO, 2 = LSD)					
Particulate Control	Integer	2	1	2	2
(1 = Fabric Filter, 2 = ESP)					
NOx Control	Integer	2	2	2	2
(1 = SCR, 2 = SNCR, 3 = LNBs, 4 = NGR)					

INPUTS

Description	Units	Case 1	Case 2	Case 3	Case 4
General Plant Technical Inputs					
Location - State	Abbrev.	ND	ND	ND	ND
MW Equivalent of Flue Gas to Control System	MW	257	257	477	477
Net Plant Heat Rate	Btu/kWhr	11,498	11,498	10,813	10,813
Plant Capacity Factor	%	85%	85%	85%	85%
Total Air Downstream of Economizer	%	120%	120%	120%	120%
Air Heater Leakage	%	0%	0%	0%	0%
Air Heater Outlet Gas Temperature	°F	300	300	300	300
Inlet Air Temperature	°F	80	80	80	80
Ambient Absolute Pressure	In. of Hg	27.86	27.86	27.86	27.86
Pressure After Air Heater	In. of H2O	-12	-12	-12	-12
Moisture in Air	lb/lb dry air	0.013	0.013	0.013	0.013
Ash Split:					
Fly Ash	%	49%	49%	49%	49%
Bottom Ash	%	51%	51%	51%	51%
Seismic Zone	Integer	0	0	0	0
Retrofit Factor	Integer	1.3	1.3	1.3	1.3
(1.0 = new, 1.3 = medium, 1.6 = difficult)					
Select Coal	Integer	7	7	7	7
Is Selected Coal a Powder River Basin Coal?	Yes / No	No	No	No	No
Economic Inputs					
Cost Basis -Year Dollars	Year	2007	2007	2007	2007
Sevice Life (levelization period)	Years	20	20	20	20
Inflation Rate	%	3%	3%	3%	3%
After Tax Discount Rate (current $'s)	%	6%	6%	6%	6%
AFDC Rate (current $'s)	%	4%	4%	4%	4%
First-year Carrying Charge (current $'s)	%	9%	9%	9%	9%
Levelized Carrying Charge (current $'s)	%	9%	9%	9%	9%
First-year Carrying Charge (constant $'s)	%	9%	9%	9%	9%
Levelized Carrying Charge (constant $'s)	%	9%	9%	9%	9%
Sales Tax	%	0%	0%	0%	0%
Escalation Rates:					
Consumables (O&M)	%	3%	3%	3%	3%
Capital Costs:					
Is Chem. Eng. Cost Index available?	Yes / No	Yes	Yes	Yes	Yes
If "Yes" input cost basis CE Plant Index.	Integer	468.2	468.2	468.2	468.2
If "No" input escalation rate.	%	3%	3%	3%	3%
Construction Labor Rate (Not Used N Calc)	$/hr	$35	$35	$35	$35
Prime Contractor's Markup	%	3%	3%	3%	3%
Operating Labor Rate	$/hr	$40	$40	$40	$40
Power Cost	Mills/kWh	35	35	35	35
Steam Cost	$/1000 lbs	3.5	3.5	3.5	3.5

Limestone Forced Oxidation (LSFO) Inputs					
Any By-Pass around the scrubber		2	2	2	2
(1 = yes, 2 = no)					
Percent of By-Passed Gas	%	0.0%	0.0%	0.0%	0.0%
SO2 Removal Required	%	95.0%	90.0%	95.0%	90.0%
L/G Ratio	gal / 1000 acf	50	50	50	50
Design Scrubber with Dibasic Acid Addition?	Integer	2	2	2	2
(1 = yes, 2 = no)					
Adiabatic Saturation Temperature	°F	135	135	135	135
Reagent Feed Ratio	Factor	1.03	1.03	1.03	1.03
(Mole CaCO3 / Mole SO2 removed)					
Scrubber Slurry Solids Concentration	Wt. %	15%	15%	15%	15%
Stacking, Landfill, Wallboard	Integer	1	1	1	1
(1 = stacking, 2 = lanfill, 3 = wallboard)					
Number of Absorbers	Integer	1	1	2	2
(Max. Capacity = 700 MW per absorber)					
Absorber Material	Integer	1	1	1	1
(1 = alloy, 2 = RLCS)					
Absorber Pressure Drop	in. H2O	6	6	6	6
Reheat Required ?	Integer	2	2	2	2
(1 = yes, 2 = no)					
Amount of Reheat	°F	0	0	0	0
Reagent Bulk Storage	Days	30	30	30	30
Reagent Cost (delivered)	$/ton	$114	$114	$114	$114
Landfill Disposal Cost	$/ton	$30	$30	$30	$30
Stacking Disposal Cost	$/ton	$6	$6	$6	$6
Credit for Gypsum Byproduct	$/ton	$0	$0	$0	$0
Maintenance Factors by Area (% of Installed Cost)					
Reagent Feed	%	3%	3%	3%	3%
SO2 Removal	%	3%	3%	3%	3%
Flue Gas Handling	%	3%	3%	3%	3%
Waste / Byproduct	%	3%	3%	3%	3%
Support Equipment	%	3%	3%	3%	3%
Contingency by Area (% of Installed Cost)					
Reagent Feed	%	20%	20%	20%	20%
SO2 Removal	%	20%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%	20%
Support Equipment	%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)					
Reagent Feed	%	10%	10%	10%	10%
SO2 Removal	%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)					
Reagent Feed	%	10%	10%	10%	10%
SO2 Removal	%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%

Lime Spray Dryer (LSD) Inputs					
SO2 Removal Required	%	90%	90%	90%	90%
Adiabatic Saturation Temperature	°F	135	135	135	135
Flue Gas Approach to Saturation	°F	25	25	25	25
Spray Dryer Outlet Temperature	°F	160	160	160	160
Reagent Feed Ratio	Factor	1.30	1.30	1.30	1.30
(Mole CaO / Mole Inlet SO2)					
Recycle Rate	Factor	7.5	7.5	7.5	7.5
(lb recycle / lb lime feed)					
Recycle Slurry Solids Concentration	Wt. %	30%	30%	30%	30%
Number of Absorbers	Integer	1	1	1	1
(Max. Capacity = 300 MW per spray dryer)					
Absorber Material	Integer	3	3	3	3
(1 = alloy, 2 = RLCS)					
Spray Dryer Pressure Drop	in. H2O	5	5	5	5
Reagent Bulk Storage	Days	30	30	30	30
Reagent Cost (delivered)	$/ton	$114	$114	$114	$114
Dry Waste Disposal Cost	$/ton	$7	$7	$7	$7
Maintenance Factors by Area (% of Installed Cost)					
Reagent Feed	%	2%	2%	2%	2%
SO2 Removal	%	2%	2%	2%	2%
Flue Gas Handling	%	2%	2%	2%	2%
Waste / Byproduct	%	2%	2%	2%	2%
Support Equipment	%	2%	2%	2%	2%
Contingency by Area (% of Installed Cost)					
Reagent Feed	%	20%	20%	20%	20%
SO2 Removal	%	20%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%	20%
Support Equipment	%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)					
Reagent Feed	%	10%	10%	10%	10%
SO2 Removal	%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)					
Reagent Feed	%	10%	10%	10%	10%
SO2 Removal	%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%
Particulate Control Inputs					
Outlet Particulate Emission Limit	lbs/MMBtu	0.03	0.015	0.03	0.03
Fabric Filter:					
Pressure Drop	in. H2O	8	8	8	8
Type (1 = Reverse Gas, 2 = Pulse Jet)	Integer	2	2	2	2
Gas-to-Cloth Ratio	ACFM/ft^2	3.5	3.5	3.5	3.5
Bag Material (RGFF fiberglass only)	Integer	3	3	3	3
(1 = Fiberglass, 2 = Nomex, 3 = Ryton)					
Bag Diameter	inches	6	6	6	6
Bag Length	feet	26	26	26	26
Bag Reach		3	3	3	3
Compartments out of Service	%	10%	10%	10%	10%
Bag Life	Years	3	3	3	3
Maintenance (% of installed cost)	%	5%	5%	5%	5%
Contingency (% of installed cost)	%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	10%	10%	10%	10%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%
ESP:					
Strength of the electric field in the ESP = E	kV/cm	10.0	10.0	10.0	10.0
Plate Spacing	in.	16	16	16	16
Plate Height	ft.	36	36	36	36
Pressure Drop	in. H2O	2	2	2	2
Maintenance (% of installed cost)	%	5%	5%	5%	5%
Contingency (% of installed cost)	%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	10%	10%	10%	10%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%